Birmingham, Alabama 35201
Telephone 205 877-7122

C. K. McCoy
Vice President, Nuclear
Vogtle Project

Georgia Power
the southern electric system

August 28, 1991

Mr. James Lieberman
Director, Office of Enforcement
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Re: Response to Demand for Information

Dear Mr. Lieberman:

This letter responds to a letter of June 3, 1991 from Mr. James Sniezek, Deputy Executive Director for Nuclear Reactor Regulation. Mr. Sniezek's letter forwarded a Demand for Information concerning an event which occurred at Georgia Power Company's Vogtle Electric Generating Plant ("VEGP") on October 12 and 13, 1988. Since Mr. Sniezek's transmittal was not to be placed in the Public Document Room until a decision in this matter is made, GPC requests that this letter and the enclosed Response be similarly treated as exempt from disclosure under 10 CFR § 2.790.

The NRC's letter and Demand for Information expresses concern that certain VEGP managers and supervisors may have intentionally disregarded Technical Specifications in an attempt to facilitate outage activities. As you may be aware, the NRC's Office of Investigations ("OI") initiated a review of this event in late January, 1990 after the NRC received an allegation stating that VEGP Unit 1 was willfully and intentionally placed in a condition prohibited by its Technical Specifications. OI's investigation was completed on March 19, 1991, more than a year after its initiation. Nonetheless, Georgia Power Company ("GPC") is convinced that an impartial and thorough review of the information supplied in the enclosed Response to the Demand for Information will conclusively demonstrate that Technical Specifications were not intentionally disregarded or willfully violated by these employees.

The enclosed Response specifically responds to the Demand for Information. As more fully explained in the enclosed

Response, the Reactor Makeup Water Storage Tank ("RMWST") discharge valves -176 and -177 were opened on the night shift of October 11-12, 1988 to permit the filling of the "chemical addition pot" with hydrogen peroxide. The hydrogen peroxide was to be added to the Reactor Coolant System ("RCS") to chemically clean the System as a pre-planned and scheduled outage activity. This shift did not recognize a Technical Specification conflict, much less commit a willful violation. As to the activities on this shift, GPC has identified the specific causes which contributed to the failure of the operators to recognize a Technical Specification compliance issue as 1) inadequate planning and procedures, and 2) inadequate training and guidance. This was aggravated by lack of experience as this was the first outage performed at Plant Vogtle. The actual context of the event, then, was a pre-planned evolution conducted for the first time at VEGP by relatively inexperienced operators who had been provided inadequate guidance.

The first opening of the subject valves on October 12, 1988 was personally directed by a Support Shift Supervisor. In accordance with the pre-planned procedure, this operator specifically supervised the actual opening of the discharge valves -176 and -177 on the night shift of October 11-12, 1988. The shift was under the general supervision of Messrs. Bowles and Cash. Messrs. Bowles and Cash, the Support Shift Supervisor, and the other shift personnel did not recognize that the plant was in a "loops not filled" condition requiring those valves to be closed and secured in position. Instead, these operators were focused on lowering the RCS level to "mid-loop" or the "top of the hot legs" which they equated with the "loops not filled" condition. This "mid-loop" condition was not reached on the night shift of October 11-12, 1988.[1] These operators, who

---

[1]GPC observes that the allegation supplied to the NRC in January, 1990 also erroneously equates a "mid-loop" elevation condition of the RCS of 188'-0" with "loops not filled" Mode 5. As with these three operators on the night shift of October 11-12, the submitter of the allegation apparently viewed the terms of "mid-loop" and "loops not filled" as interchangeable. Such is not the case. On the morning of October 12, 1988 by about 3:30 a.m. (CT) the RCS water level had been drained down to the 189'-10" level and the steam generator tube bundles had been drained; the Plant was in Mode 5 with loops not filled, and Technical Specification § 3.4.1.4.2 was applicable. However, the RCS water level had not yet been lowered to a "mid-loop" condition as then understood by these operators.

possessed inadequate training and guidance concerning the "loops not filled" status of the RCS, believed that the condition triggering the Technical Specification had not yet been reached.

Later, on the morning of October 12, 1988, the on-coming Shift Supervisor identified the Technical Specification as a potential constraint to the chemical cleaning evolution. At that point in time, somewhere between 5:07 and 5:33 a.m. (CT), Mr. Bowles, who was being relieved as Shift Supervisor, recognized for the first time the potential applicability of the Technical Specification with respect to the opening of RMWST valves -176 and -177 on his shift. Mr. Bowles recorded a "late entry" which acknowledged his crew's activities and the specific Technical Specification at issue. This log entry, in GPC's view, confirms the straightforward, simplistic manner in which the chemical cleaning evolution was approached by the night shift and the late realization that Mode 5 "loops not filled" might have been entered. Again, to GPC's knowledge, no night shift crew member held any reservation or concern, or identified any regulatory constraint, applicable to the pre-planned and scheduled chemical cleaning evolution.

In the Demand for Information and its transmittal letter, the NRC states that OI has concluded previously that this event involved willful Technical Specification violations. GPC takes these charges very seriously and, accordingly, we have conducted a thorough review of this matter, including the portions of the OI record available to us. GPC has substantial reservations as to the completeness and accuracy of the OI review. With respect to the licensed personnel on the night shift of October 11-12, 1988, the record is clear that they were unaware of the implications of Technical Specification 3.4.1.4.2 to scheduled activities prior to shift turnover. This apparent deficiency in OI's analysis is underscored by OI's failure to interview the SRO-licensed Support Shift Supervisor who personally supervised the addition of hydrogen peroxide to the chemical mixing tank during the night shift.

GPC also believes that OI ignored the institutional causes of the entrance into the LCO by this shift crew. The specific procedure relevant and central to this activity was the detailed procedure for the outage chemistry activities contemplated for Unit 1 which was developed by the Health Physics and Chemistry Department (Procedure 49006-C, approved June 9, 1988). This procedure, at page 15 of 36, provides for the drain-down to mid-loop and requires that "when the drain-down is complete, Hydrogen Peroxide should be added." The developer of this procedure had incorrectly concluded that no change to Technical Specification was involved.

With respect to the activities of the day shift of October 12, 1988, GPC's enclosed response reviews the actions of the Operations Manager, Mr. W. F. (Skip) Kitchens relative to his interpretation of Technical Specification 3.4.1.4.2 as permitting the RMWST valves to be opened for a short period of time for chemical cleaning activity. Substantial doubt exists that Mr. Kitchens knew, or should have known, that the manipulation to the open position of the RMWST valves was prohibited by the Technical Specification (as indicated in the Demand). Also, no doubt exists that he reached his interpretation that his actions were allowed by the Technical Specification after conscientiously and openly reviewing the matter, after obtaining advice from a more experienced Operations manager and others, after reviewing documentation relevant to interpreting the Technical Specification, and after applying principles of Technical Specification compliance which are established and recognized in the industry. His actions were consistent with NRC guidance issued prior to the activity which stated that "the NRC endorses Voluntary Entry into the Action Statement Conditions and has structured the Technical Specification to permit the licensee to exercise judgment within the latitude permitted by the Action Statement language in the Technical Specifications." Thus, if his actions led to a Technical Specification violation, it certainly was not a willful violation.

Moreover, the enclosed Response establishes that reasonable minds can differ as to whether the actions taken on October 12-13, 1988 violated NRC requirements. These actions were viewed, in good faith, as voluntary entries into a Limiting Condition for Operation ("LCO") in which the required action was completed within an "immediate" duration as required by the Action Statement. As one basis for this proposition, GPC is aware of a more recent, similar event reviewed by Region II involving the voluntary entry into a Limiting Condition for Operation at another facility where the required "immediate" action was viewed by the licensed operator as permitting voluntary entry into the LCO for a duration of time for a planned evolution. This demonstrates that other operators are still making this judgment.

GPC's position that well-intentioned persons can reasonably interpret Technical Specification 3.1.4.1.2 as permitting voluntary entrance for short durations is supported, also, by the history of the January, 1990 allegation which prompted the NRC's review of this matter. The allegation was submitted anonymously by a former manager and Plant Review Board member. On November 17, 1989 this individual voted that the October, 1988 event was not reportable to the NRC under 10 CFR § 50.73, reflecting his conclusion at that time that the events were not prohibited by Technical Specification. He testified to this effect on February 8, 1990 in a transcribed OI interview. These events, and the fact that NRC and industry representatives have long recognized the ambiguity inherent in the use of the word "immediate" in Technical Specifications, suggest that additional NRC guidance to licensed operators is far more appropriate than formal enforcement action.

OI's oversight of relevant and material facts surrounding the October, 1988 chemical cleaning also is reflected by an apparent total discounting of Mr. Kitchens' good faith, straightforward efforts in interpretation of the relevant Technical Specification. Mr. Kitchens postponed the chemical cleaning, applied a well-established and observed principle of Technical Specification construction (i.e., voluntary entrance into an LCO is permissible provided that the associated Action Statement is complied with), consciously reviewed the relevant portions of the FSAR, and obtained input from a more experienced Operations manager in addressing the meaning and application of the Technical Specification. This review was open and shared with those on shift and others, perhaps including an NRC Resident Inspector. For OI to reach a conclusion of willful and intentional wrongdoing while possessing this information is inconceivable.

After a careful and thorough review, GPC has concluded this matter is not reflective of wrongdoing on the part of VEGP licensed operators but is indicative of historic institutional weaknesses (i.e., planning and procedures for infrequent evolutions and training and guidance for operators responsible for such evolutions) and ambiguous terminology in Technical Specifications in light of historic practices and interpretations (i.e., routine voluntary entrance into LCOs for maintenance activities; "immediate" durations in LCOs and associated action statements). NRC representatives have indicated that significant internal discussions and disagreements concerning the appropriate interpretation of the subject Technical Specification and the reasonableness of Mr. Kitchens' interpretation preceded the issuance of the Demand for Information. This discussion, the extensive time taken by OI in reaching a conclusion (over a year since completion of interviews of the operators and Mr. Kitchens), and the clear potential in the future for similarly-situated operators to reach the same type of conclusion demonstrate the inappropriateness of formal enforcement action in this matter.

GPC recognizes that the NRC now views "immediate" LCOs and associated action statements as action statements which implicitly prohibit voluntary entrance. The Company has already implemented measures to assure that this position is implemented by VEGP operators.

The information provided herein is true and correct to the best of my knowledge.

Sincerely yours,

C Kenneth McCoy

C. Kenneth McCoy

Sworn to and subscribed
before me this 28 day of
August, 1991.

Mary N. Bentley
Notary Public

My Commission expires:

CKM:njf
Enclosure

cc: Mr. James Sniezek
Mr. Stewart Ebneter
Mr. Alan Herdt
Assistant General Counsel
for Hearings and Enforcement
Mr. David B. Matthews

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of

GEORGIA POWER COMPANY, *et al*.	*	Docket Nos. 50-424 50-425
(Vogtle Electric Generating Plant, Units 1 and 2)	*	EA 91-063

GEORGIA POWER COMPANY'S RESPONSE
TO THE NRC'S JUNE 3, 1991
DEMAND FOR INFORMATION

TABLE OF CONTENTS

TABLE OF CONTENTS, Continued

I. INTRODUCTION.

On June 3, 1991, the Nuclear Regulatory Commission ("NRC") issued a "Notice of Enforcement Conference and Demand for Information" to the Georgia Power Company ("GPC" or the "Company") with respect to the addition of chemicals to the reactor coolant system of Vogtle Electric Generating Plant ("VEGP") Unit 1 on October 12 and 13, 1988, during the first refueling outage of that unit. The Notice stated that the event involved "the apparent willful violation of Technical Specification 3.4.1.4.2" which had been investigated by the NRC in response to information the NRC received in January 1990. The Notice contained a "Demand for Information" listing five specific items of information which GPC was to provide. A similar Notice of Enforcement Conference and Demand for Information was sent to Mr. W. F. Kitchens, the VEGP Manager of Operations during the event. Also, separate Demands for Information were sent to Mr. J. P. Cash and Mr. J. E. Bowles, who were licensed Senior Reactor Operators "on shift" on October 11-12, 1988.

Following a brief background discussion (Section II), GPC provides herein (Sections III.A through III.E), the specific information required by the Demand for Information. Exhibits 1-47, referred to herein, are included herewith, separately bound as "Appendix I." Attachments 1, 2 and 3, referred to herein, are included herewith, separately bound as "Appendix II."

II. BACKGROUND.

A. The First VEGP Unit 1 Refueling Outage And The Chemical Cleaning Process.

The first VEGP Unit 1 refueling outage (sometimes referred to as "1R1") began on October 8, 1988 and lasted 52 days. Numerous major activities typical of a first refueling outage were performed. Also, the addition of hydrogen peroxide to the Reactor Coolant System ("RCS") was scheduled to be performed during the Cold Shutdown mode, as a planned evolution.

Addition of hydrogen peroxide to the RCS is an established and accepted method of chemically cleaning the internals of the RCS in order to remove contaminated particles (referred to as "crud") such that the radiation exposure to individuals working in and around the RCS during the outage is significantly reduced. The procedure is referred to as a "crud burst" or "chemical cleaning" and is performed during Cold Shutdown (Mode 5) prior to opening up the RCS for refueling (Mode 6). While the procedure may be performed with the RCS full, it may be, and has been, performed at other plants with a reduced RCS coolant inventory.

Planning for the chemical addition evolution at VEGP during the 1R1 outage began in December 1987. By April 1988, a decision had been made to add the chemicals while the RCS was at a reduced inventory pursuant to the recommendation of the VEGP Health Physics and Chemistry Department. The 1R1 outage schedule identifying the chemical addition evolution was approved by the VEGP General Manager after it had been approved by all VEGP Department Managers. A more detailed discussion of the planning process for the 1R1 outage relative to this evolution is provided in Section III.D of this response.

In the case of VEGP, the addition of hydrogen peroxide to the RCS was to be accomplished with the Chemical and Volume Control System ("CVCS"). As illustrated on the simplified piping diagram attached as Exhibit 1, Valve 177 controls the discharge of unborated water from the Reactor Makeup Water Storage Tank ("RMWST"), and Valves 175, 176, and 183, located downstream of Valve 177, govern three independent flow paths leading to the RCS. The flow path through Valve 176 is the one used to add chemicals to the RCS and Valve 176 regulates the input of RMWST water into the Chemical Mixing Tank (also referred to as the "Chemical Mixing Pot" or "Chem. Add Pot"). Therefore, to add RMWST water to the Chemical Mixing Tank, Valves 177 and 176 must be opened. Valve 181 (the outlet valve), must also be opened before the discharge from the Chemical Mixing Tank can flow into the RCS.

B. The VEGP Technical Specifications And Facility Safety Analysis Report.

1. VEGP Technical Specification § 3.4.1.4.2.

From March 1987, when the Unit 1 operating license was issued, through 1989, Technical Specification ("Tech. Spec.") § 3.4.1.4.2 required, in relevant part, that the RMWST discharge Valves 175, 176, 177, and 183 be closed and secured in position while the reactor is in Mode 5 with the RCS in the "Loops Not Filled" condition.

The Westinghouse analysis of the boron dilution accident divides Mode 5 into two conditions: Mode 5a, "Loops Filled," and Mode 5b, "Loops Not Filled." The "Loops Not Filled" condition is not defined in the VEGP Tech. Specs. Also, in October 1988, the "Loops Not Filled" condition had not been explicitly defined for the VEGP operators during their training or in any guidance documents or procedures. The Westinghouse analysis of the boron dilution accident defined "Loops Not Filled" based on volumes which equated approximately with a RCS water level below 192 feet or when the RCS piping, including the primary side of the steam generator tubes, was not full (e.g., there was an air void somewhere in the RCS piping, including the primary side of the steam generators). See Exhibit 17.

The relevant "Action Statement" for Tech. Spec. § 3.4.1.4.2 reads:

> With the [RMWST discharge valves] not closed and secured in position, immediately close and secure in position the RMWST discharge valves.

See Tech. Spec. § 3.4.1.4 2, attached as Exhibit 2, sheet 1 of 2. The "Bases" section of the Tech. Specs. explains the purpose of Tech. Spec. § 3.4.1.4.2 as follows:

> The locking closed of the required valves in Mode 5 (with the loops not filled) precludes the possibility of uncontrolled boron dilution of the filled portion of the Reactor Coolant System. This action prevents flow to the RCS of unborated water by closing flowpaths from sources of unborated water. These limitations are consistent with the initial conditions assumed for the boron dilution accident in the safety analysis.

See Exhibit 2, sheet 2 of 2.

2. VEGP Facility Safety Analysis Report, Section 15.4.6.

Section 15.4.6 of the VEGP Facility Safety Analysis Report ("FSAR") describes the analysis of a boron dilution accident resulting from a malfunction in the CVCS.

In October 1988, FSAR § 15.4.6 contained the following language in Section 15.4.6.2.2.2:

> For dilution during cold shutdown, the Technical Specifications provide the required shutdown margin as a function of RCS boron concentration. The specified shutdown margin ensures that the operator has 15 min from the time of the high flux at shutdown alarm to the total loss of shutdown margin.

See Exhibit 3 at p. 15.4.6-4. Additionally, Section 15.4.6.2.1.2 expressly stated that an analysis had been performed "to evaluate boron dilution events during cold shutdown." It identified four "initiators" which had been analyzed, including the "failure to secure chemical addition," but that initiator was not identified as the most limiting. It also included the following paragraph at the very end of the section:

> Since the active volumes considered are so small in cold shutdown with the reactor coolant loops drained, it was determined that the same valves locked out in refueling would need to be locked out in cold shutdown when the reactor coolant loops are drained.

See Exhibit 3 at p. 15.4.5-2a. With respect to refueling, FSAR § 15.4.6.2 provided that dilution during Mode 6 could not occur due to administrative controls which isolated the RCS from potential sources of unborated water, including the RMWST discharge valves which "will be locked closed during refueling operations." See Exhibit 3, Sections 15.4.6.2.1.1 and 15.4.6.2.2.1, at pp. 15.4.6-2 and -4, respectively.

It should be noted that prior to December 1986, FSAR § 15.4.6 discussed a boron dilution accident analysis of Mode 5b which did exist at that time for the initiator "failure to secure chemical addition." That analysis was revised in December 1986 and, thereafter, it no longer contained an analysis of Mode 5b. However, only piecemeal changes were made to FSAR § 15.4.6 in December 1986 to reflect the then current boron dilution analysis. The result was a patchwork discussion which suggested that an analysis of Mode 5b still existed while, at the same time, it also attempted to explain that administrative controls were necessary in Mode 5b because such an analysis no longer existed. For a more extensive discussion of the evolution of FSAR § 15.4.6, as well as a discussion of NRC Safety Evaluation Report § 15.4.6, see Attachment 1.

III. GEORGIA POWER COMPANY'S DETAILED RESPONSE TO SECTION III OF THE NRC JUNE 3, 1991 DEMAND FOR INFORMATION.

A. The Actions Of Messrs. Kitchens, Cash And Bowles With Respect To The Addition Of Chemicals To The VEGP Unit 1 Reactor Coolant System On October 12 And 13, 1988.[1]

1. The Night Shift of October 11-12, 1988 and the Actions of Messrs. Bowles and Cash.

On the morning of October 11, 1988, the VEGP Unit 1 reactor was in Cold Shutdown with the Loops Filled when the "Day Shift" bega duty. See VEGP Unit 1 Shift Supervisor Log for October 11-

[1] The events described herein are, in the Company's opinion, the most probable sequence of events based on (1) the information provided to the Company by the various individuals involved, and (2) a review of those OI interview transcripts which were made available to the Company.

13, 1988, attached as Exhibit 4, entry at 0536 hours on October 11, and VEGP Unit 1 Control Log for October 11-13, 1988, attached as Exhibit 5, entry at 0602 hours on October 11.[2] Mr. Jeffrey T. Gasser was the Unit Shift Supervisor on the Day Shift and Mr. John D. Hopkins was the On-Shift Operations Supervisor ("OSOS").[3] At 7:21 a.m. CT that morning, the Day Shift began draining down the RCS in preparation for refueling. See Exhibit 4 and Exhibit 5 entries at 0721 hours on October 11.

At 9:35 a.m. CT that morning, red clearance tags were hung by the Day Shift on dilution flow path valves (Nos. 175, 176, 177, 181, 183 and 226) pursuant to VEGP Procedure 12006-C, § D4.2.14. See VEGP Procedure 12006-C, Rev. No. 9 "Working Copy," attached as Exhibit 6, at p. 31; see also Clearance Sheet for Clearance No. 1-88-371, attached as Exhibit 10.[4] That procedure required those valves to be closed prior to draining the RCS to "25% cold calibrate pressurizer level," which level corresponds to a RCS water level of approximately 219 feet. The clearance

---

[2] Although VEGP is in the Eastern Time Zone, the time entries on the VEGP Shift Supervisor and Control Room Logs reflect Central Time (hereinafter "CT") to correspond with The Southern Company energy control center, located in the Central Time Zone in Alabama.

[3] The hierarchy of the VEGP Operations Department relevant to this discussion, beginning with the department head, was first the Operations Manager, second the Deputy Manager of Operations, third the Operations Superintendents, fourth the On-Shift Operations Supervisors, and fifth the Unit Shift Supervisors. In addition, the following personnel provided direct support to and were under the direction of the Unit Shift Supervisors: Support Shift Supervisors, Reactor Operators, Balance-Of-Plant Operators and Plant Equipment Operators.

[4] The red clearance tags ensured that the valves could not be manipulated without first obtaining the proper approvals to "release" the clearance. See VEGP Procedure 00304-C, Rev. No. 14, attached as Exhibit 7, "WARNING," at p. 11. At that time, VEGP procedures permitted the use of clearance tags to administratively control small valves which could not feasibly be locked but were required under the Tech. Specs. to be "closed and secured in position." See VEGP Procedure 10019-C, Rev. No. 4, attached as Exhibit 8, § 5.1.4, p. 2. However, as a result of an April 1990 NRC Notice of Violation, GPC revised its procedures to require a locking mechanism, and to eliminate the use of clearance tags, when the Tech. Specs. require valves to be secured in position. See NRC Inspection Report Nos. 50-424/91-14 and 50-425/91-14, dated July 19, 1991, attached as Exhibit 9, Details § 3.1, at p. 10.

tags were verified by the Day Shift at 10:53 a.m. CT. See Exhibit 10.

On the evening of October 11, 1988, the Operations Department "Night Shift" crew relieved the Day Shift and Mr. John Bowles was the on-coming Unit Shift Supervisor, Mr. Jimmy Paul Cash, the OSOS, and Mr. W. Thomas Ryan, the Support Shift Supervisor. See Exhibit 4 entry at 1736 hours on October 11.[5] At the start of the Night Shift, the RCS water level had been drained down to the 194' level and activities were in progress to further drain the RCS. Id. Either preparation for the displacement or initial displacement (by injection of nitrogen gas) of primary water from the steam generator tube bundles was initiated at 7:06 p.m. CT on October 11 and the displacement was completed by 1:50 a.m. CT on October 12, 1988. See Exhibit 5 entries at 1906 hours on October 11 and 0150 hours on October 12. By about 3:30 a.m. CT on the morning of October 12, 1988, the RCS water level had been drained down to the 189'-10" level. See Exhibit 5 entry at 0333 hours on October 12.

At about 3:00 a.m. CT on October 12, in preparation for the planned addition of hydrogen peroxide to the RCS, a "Functional Test Form" was authorized by the Support Shift Supervisor and completed to release Clearance No. 1-88-371 from RMWST discharge Valves 176, 177 and 181. See Functional Test Form for Clearance 1-88-371, attached as Exhibit 11, entries at 0250 and 0310 hours.[6] Clearance No. 1-88-371 was later restored at 4:15 a.m. CT and verified at 4:25 a.m. CT. See Exhibit 11 entries at 0415 and 425 hours.

At 4:00 a.m. CT on October 12, Mr. Ryan supervised Plant Equipment Operators and coordinated with the Chemistry Department in order to load approximately five bottles of hydrogen peroxide into the Chemical Mixing Tank and fill the tank with water from the RMWST. VEGP Procedure 13007-1, Rev. No. 2 (attached as

---

[5] As this was the first refueling outage at the VEGP site, it was a relatively new experience for a number of the VEGP operators, including Messrs. Cash, Bowles, Ryan and Hopkins, and, at times relevant to the chemical addition activities, the Unit 1 Control Room was busy.

[6] VEGP Procedure 00304-C, § 4.7, entitled "Performing Functional Tests," contains provisions for releasing a clearance from a piece of equipment on a temporary basis. See Exhibit 7 at p. 19-21. Its application was not limited to performance of a functional test; the established practice at VEGP at the time was to use "functionals" when the operators wished to retain administrative control over a piece of equipment in operation until the clearance was restored.

Exhibit 12), §§ 4.7.1 through 4.7.4, addressed the isolation of the Chemical Mixing Tank (to permit the loading of chemicals into the tank pursuant to VEGP Procedure 35110-C) and the opening of Valve 176 in order to fill the tank with RMWST water. See Exhibit 12 at pp. 12-13. The Functional Test Form authorized the opening of Valve 177. Because of difficulty in verifying the RCS water level measurement and/or the impending shift turnover, the chemicals were not injected into the RCS (§§ 4.7.5 through 4.7.12 of Procedure 13007-1 (Exhibit 12)) at that time or at any time during the Night Shift. Mr. Bowles recorded at 4:00 a.m. CT the following entry in the Shift Supervisor Log at the time the chemicals were loaded:

> CVCS chemical mixing pot loaded with hydrogen peroxide. Functional clearance 1-88-371 to allow sending chemicals.

See Exhibit 4 entry at 0400 hours on October 12.

Between 5:07 a.m. and 5:33 a.m. CT on October 12, 1988, the on-coming Day Shift supervision for the first time raised a question concerning the application of Tech. Spec. § 3.4.1.4.2. Following this discussion, Mr. Bowles added the following to the Shift Supervisor Log as a "Late Entry" ("LE"):

> Valves 1-1208-U4-177, 1-1208-U4-176, and 1-1208-U4-181 opened to fill CVCS drain pot. Above mentioned valves immediately shut upon completion of fill in accordance with Tech Spec 3.4.1.4.2.

See Exhibit 4 entry "LE 0400" directly following the entry at 0507 hours on October 12. Although Mr. Bowles identified RMWST discharge Valves 176, 177 and 181 in the Late Entry, it is clear that Valve 181, which controlled the discharge from the Chemical Mixing Tank to the RCS, had not been opened.

Messrs. Bowles, Cash and Ryan were unaware of any conflict between the Tech. Specs. and the opening of RMWST discharge Valves 176 and 177 at the time of the operation of those valves at 4:00 a.m. CT on October 12, 1988. No one on the Night Shift raised a question concerning the operation of the valves. In fact, as will be discussed further below, Mr. Bowles and Mr. Cash did not believe, at the time the valves were opened, that the RCS was in the "Loops Not Filled" condition, a prerequisite to the applicability of Tech. Spec. § 3.4.1.4.2. However, once Mr. Bowles discussed the Tech. Spec. with the on-coming Day Shift supervision, both he and Mr. Cash then considered for the first time the applicability of the Tech. Spec. At that point in time (5:07-5:33 a.m. CT) Mr. Bowles recorded the "LE 0400" entry quoted above.

The Functional Test Form permitting the 4:00 a.m. valve manipulation (Exhibit 11) does not indicate the period of time that RMWST discharge Valves 176 and 177 were open; it only indicates the period of time that the valves were released from Clearance No. 1-88-371 (i.e., about one hour).

2. The Day Shift of October 12, 1988 and the Actions of Mr. Kitchens.

At 5:33 a.m. CT on October 12, 1988, the Day Shift relieved the Night Shift. Mr. Jeff Gasser was the on-coming Unit Shift Supervisor and Mr. John D. Hopkins was the on-coming OSOS. See Exhibit 4 entries at 0533 and 0535 hours on October 12. Messrs. Gasser and Hopkins realized when they reviewed the log books in preparation for beginning their shift, that the prior Night Shift had opened the RMWST valves. Messrs. Hopkins and Gasser had a question about the propriety of opening the RMWST discharge valves in light of Tech. Spec. § 3.4.1.4.2, and the matter was discussed with the prior Night Shift Unit Shift Supervisor, Mr. Bowles.[7] As discussed above, that led Mr. Bowles to the decision to record the "LE 0400" entry on the morning of the 12th.

Since the chemical addition remained to be performed during his shift, Mr. Hopkins discussed the implication of Tech. Spec. § 3.4.1.4.2 with Mr. Gasser and with Mr. W. F. "Skip" Kitchens, the Operations Manager at the time, who was in the Control Room. Mr. Kitchens told Mr. Hopkins to suspend chemical addition activities until they, Mr. Kitchens and Mr. Hopkins, could discuss the matter again after the 6:00 a.m. CT combination OSOS/outage status meeting that morning.

The OSOS/outage status meeting was attended by about 20 individuals, including the OSOS, the Outage & Planning Manager, Mr. Kitchens, and, we believe, an NRC Resident Inspector. While discussing the outage in general, the chemical addition evolution was raised as an item since, pursuant to the schedule, the RCS could not be opened until the chemical cleaning was complete. Mr. Kitchens believes that he explained at the meeting that the chemical addition had been put on hold because a Shift Supervisor had raised a question concerning Tech. Specs. which Mr. Kitchens wanted to review.

---

[7] Without question, the focus of the prior Night and Day Shifts was on achieving the condition of "Mid-loop" elevation, and not the achievement of a "Loops Not Filled" condition. In contrast to Messrs. Bowles and Cash, Mr. Hopkins recognized the possibility that the RCS was in the Loops Not Filled condition and Mr. Gasser, who was apparently the only licensed individual to do so, concluded that the RCS was in the Loops Not Filled condition because primary water had been displaced from the steam generator tubes.

At about 6:10 a.m. CT, following the OSOS/outage status meeting, Messrs. Kitchens and Hopkins reviewed the Tech. Specs. and the VEGP FSAR and they spoke with Mr. Walter Marsh, the Deputy Manager of Operations at the time. Mr. Hopkins concluded, with the concurrence of Mr. Kitchens, that, assuming the RCS was in the Loops Not Filled condition, voluntary entry into the LCO of Tech. Spec. § 3.4.1.4.2 for a maximum of five minutes would be conservative and would not violate the Tech. Spec. Mr. Hopkins' conclusion was based on Mr. Kitchens' determination that opening the RMWST discharge valves for no more than 15 minutes would be permissible. Mr. Gasser concurred with Mr. Hopkins' decision[8] and no one on-shift raised any concerns with the decision.

After reaching their conclusion, Messrs. Gasser and Hopkins authorized the release of Clearance No. 1-88-371 through the completion of the Functional Test Forms attached as Exhibit 13. They directed their shift personnel to open the RMWST discharge valves for no more than five minutes and to contact the Control Room at the moment the valves were opened and, again, at the moment the valves were closed.[9] The chemical addition procedure was performed by Messrs. Gasser and Hopkins a total of three times over the course of October 12 and 13, 1988. They were careful to record in the Shift Supervisor Log the time that the specific valves were open during each injection. See Exhibit 4 entries at 0705 and 0709 hours on October 12 and entries at 1030, 1034, LE 1640 and LE 1644 hours on October 13.[10]

Subsequently, Messrs. Hopkins and Kitchens contacted the Manager of Nuclear Safety and Compliance ("NSAC") at VEGP, Mr. James E. Swartzwelder, on separate occasions. Mr. Swartzwelder, who was also a licensed Senior Reactor Operator and an experienced operator, concurred that a permissible interpretation

---

[8] At shift turnover, Mr. Gasser had developed a preliminary conclusion that a short-duration entrance into the LCO of Tech. Spec. § 3.4.1.4.2, voluntarily made, was permissible so long as there was compliance with the Action Statement. When he raised the issue, he sought clarification from his supervisor. Consequently, the question posed to Mr. Kitchens had been tentatively, albeit not conclusively, answered as permitting the evolution. Mr. Kitchens nonetheless deferred the evolution until time permitted an adequate review.

[9] Although GPC is aware of an allegation that Mr. Kitchens personally manipulated the valves, it is clear that the valves were manipulated by others under the direction of Messrs. Gasser and Hopkins.

[10] For convenience, the Company has prepared a chronology of the pertinent events of October 11-13, 1988, which is attached as Exhibit 14.

had been made. Nonetheless, Messrs. Hopkins and/or Kitchens asked Mr. Swartzwelder to initiate a formal amendment to Tech. Spec. § 3.4.1.4.2 to clarify the acceptability of the chemical addition decision for the future, since it was likely that the chemical cleaning would be conducted during future refueling outages.

B. Messrs. Kitchens, Cash And Bowles Should Not Be Removed From Licensed Activities Because They Did Not Willfully Violate The Tech. Specs.

1. The Standards for "Willfulness" and for Enforcement Against Individuals.

In its June 3, 1991 Demand for Information, the NRC states that the NRC's Office of Investigation ("OI") completed an investigation of the October 12-13, 1988 chemical addition evolution. OI concluded that Tech. Spec. § 3.4.1.4.2 was "knowingly and intentionally violated by the VEGP Operations Shift Supervisors with the express knowledge and, in the case of one shift crew, the concurrence of the Operations Manager." In the Demand for Information, the NRC goes on to add that "[b]ased on the investigative findings, the NRC is concerned that an NRC-licensed VEGP manager and NRC-licensed supervisors may have intentionally disregarded Technical Specifications in an attempt to facilitate outage activities." In its Demand for Information, the NRC has specifically requested that the Company explain "why Messrs. W. F. Kitchens, J. P. Cash and J. E. Bowles should not be removed from 10 CFR Part 50 and 10 CFR Part 55 licensed activities...."

GPC has carefully reviewed the facts surrounding the October 12-13, 1988 chemical addition evolution as discussed above. As will be discussed below, the facts in this case do not support a conclusion that any violation of Tech. Specs. that may have occurred was a "willful" violation as that term is used in the Atomic Energy Act and by the NRC. Additionally, in accordance with the NRC's Enforcement Policy (10 C.F.R. Part 2, Appendix C), the actions of the individuals in question in this case do not warrant enforcement sanctions directly affecting either their licenses or their continued employment in Part 50 and Part 55 licensed activities.

Before addressing the specific facts as they pertain to each of the individual operators whose actions have been questioned, and before responding to the NRC's specific request in the Demand for Information, a brief review of the standard of "willfulness" is warranted. Moreover, we briefly outline, as we understand it, NRC's policy regarding the extraordinary measure of imposing enforcement sanctions directly against individuals employed at licensed facilities such as Vogtle. These standards and guidelines will allow us to review the facts in appropriate perspective and respond to the Demand for Information.

a. The "Willfulness" Standard.

Chapter 18 of the Atomic Energy Act of 1954, as amended (the "1954 Act"), specifies various criminal penalties for willful violations of the statute and regulations or orders of the NRC. 42 U.S.C. §§ 2271-2284. While the term "willful" is not defined in the 1954 Act, the statute's legislative history suggests that a very high standard was intended. The Conference Report accompanying the 1980 amendment of Section 223 of the 1954 Act explains that the "knowing and willful" intent required for a violation of that particular section is a "high standard for state of mind." H.R. Conf. Rep. No. 1070, 96th Cong., 2d Sess., 30 (1980), reprinted in 1980 U.S. Code Cong. & Admin. News 2260, 2274.

The NRC's interpretation of the word "willful" is set forth in the Enforcement Policy. Section III of the Enforcement Policy reads, in pertinent part, as follows:

> The term "willfulness" as used here embraces a spectrum of violations ranging from deliberate intent to violate or falsify to and including careless disregard for requirements. Willfulness does not include acts which do not rise to the level of careless disregard, e.g., inadvertent clerical errors in a document submitted to the NRC.

10 C.F.R. Part 2, Appendix C, § III. Elsewhere in Section III, the NRC states that "indications" of willfulness include "careless disregard of requirements" and "deception." Id. Finally, Section V.E. of the Policy Statement describes careless disregard as involving "more than mere negligence."

What this means is that willful violations, for purposes of NRC enforcement actions, require a particular state of mind that goes beyond those instances in which actions are taken knowingly (that is, in this case, more than knowledge that the RMWST valves had been or were to be opened). A willful violation of NRC requirements must involve an additional element of the actor's mental state, either deliberate intent to violate or, at a minimum, careless disregard for agency requirements. Moreover, careless disregard is something more than mere negligence (e.g., more than simply unreasonable logic under the circumstances). The logical inference resulting from Appendix C is that if a licensee or individual operator in good faith considers and attempts to comply with NRC requirements, he or she will not be deemed to have acted with either deliberate intent to violate or careless disregard for regulations and, therefore, will not be held accountable for a willful violation.[11]

Federal and NRC case law, in defining "willfulness" and "careless disregard," similarly indicate that a willful violation cannot result if an individual or licensee had considered NRC's requirements and reached a conclusion, even if incorrect, that the actions in questions would not violate relevant statutory or regulatory provisions. The existence of a reasoned justification defeats a charge of willfulness, despite the fact that a particular action was taken, knowingly and intentionally, that was ultimately found to violate NRC requirements.

In Wrangler Laboratories, LBP-89-39, 30 NRC 746 (1989), the Board ruled that the licensee's failures were not evidence of careless disregard of NRC regulations or of willful intent to violate NRC requirements. 30 NRC at 780. It did so because the licensee made "serious albeit defective" efforts to comply with NRC regulations. Id. For instance, the licensee's decision not to report events, as required, to the NRC was based on "multiple incorrect assessments and misapprehension of his regulatory obligations." Id. Nevertheless, the Board found that reasons credible to the licensee existed for not complying with NRC requirements. Even though these reasons were factually incorrect, the Board held that they prevented a conclusion that there was a willful violation of NRC requirements or careless disregard of regulations.

Another NRC decision underscores the conclusion that a violation (assuming one occurred) is not "willful" if there was a reasoned contemporaneous justification for the action taken -- even if the basis for that justification is later found to be factually incorrect. See Reich Geo-Physical, Inc., ALJ-85-1, 22 NRC 941 (1985). The administrative law judge in that case examined the factual basis for each of six alleged willful violations. Ultimately, he determined that two of the six violations did not rise to the level of careless disregard and, therefore, were not "willful" in nature. In both instances, the rationale supporting this conclusion was that, because the licensee had a reasonable basis for believing it was not violating NRC requirements, it could not be charged with careless disregard or, concomitantly, a willful violation. Id. at 954, 957-58.

---

[11]GPC observes that even if the licensed operator acted negligently (i.e., contrary to what a reasonable person would have done under similar circumstances) in attempting to comply, the operator's action will not constitute a willful violation, absent gross negligence or recklessness. In other words, a bona fide attempt to comply with requirements defeats a finding of "intentional" misconduct or "careless disregard" for regulations.

The Supreme Court has also, on several occasions, addressed the topic of willful violations. In doing so, it has consistently held that the word "willful" is generally understood to refer to conduct that is not merely negligent. E.g., McLaughlin v. Richland Shoe Co., 486 U.S. 128, 108 S. Ct. 1677, 1681 (1988); United States v. Murdock, 290 U.S. 389, 54 S. Ct. 223, 225 (1933) ("[t]he word [willful] often denotes an act which is intentional, or knowing, or voluntary, as distinguished from accidental"). "Willfully" means

> purposely or obstinately and is designed to describe the attitude of a [licensee], who, having a free will or choice, either intentionally disregards the statute or is plainly indifferent to its requirements.

Alabama Power Co. v. Federal Energy Regulatory Comm'n, 584 F.2d 750, 752 (5th Cir. 1978) (quoting St. Louis & S.F. Ry. v. United States, 169 F. 69, 71 (8th Cir. 1909)). It is a term employed to characterize an action that is done without grounds for believing that it is lawful. Murdock, 54 S. Ct. at 225. Furthermore, the Court has held that if one acts reasonably, or even unreasonably (but not recklessly), in determining his legal obligations, he cannot be charged with a willful violation. McLaughlin, 108 S. Ct. at 1682 and n. 13.

Based on this precedent, and consistent with the underlying facts, the Company concludes that Messrs. Cash, Bowles and Kitchens clearly should not be found to have committed either an intentional violation of NRC requirements or to have acted with careless disregard for those requirements. With respect to Messrs. Cash and Bowles, as will be discussed further below, these two individuals never made a conscious decision that their actions would or would not violate Tech. Specs. Rather, apparently due to insufficient training and guidance, they were unaware that the plant was, or might have been, in the Loops Not Filled condition and assumed that Tech. Spec. § 3.4.1.4.2 did not apply. While, in retrospect, this may have been an error, their actions did not constitute "careless disregard" of the Tech. Specs., as those terms have been construed by the NRC and the courts. In the case of Mr. Kitchens, he also did not intentionally violate or carelessly disregard the Tech. Specs. On the contrary, he made the conservative assumption that Tech. Spec. § 3.4.1.4.2 applied and made a reasonable, good faith decision that the planned evolution would be in compliance therewith. His actions did not amount to a willful violation.

b. Enforcement Actions Involving Individuals.

The NRC, in its Enforcement Policy, has previously recognized that enforcement actions directly impacting individuals are "significant personnel actions, which will [or should be] closely controlled and judiciously applied." 10 C.F.R. Part 2, Appendix C, Section V.E. As previously noted, the Company does not believe that this extreme form of sanction is warranted or supportable in this instance.

Section V.E. of the Enforcement Policy specifies that "[a]n enforcement action will normally be taken [against an individual] only when there is little doubt that the individual fully understood, or should have understood, his or her responsibility; knew, or should have known, the required actions; and knowingly, or with careless disregard (i.e., with more than mere negligence) failed to take actions which have actual or potential safety significance." Id.[12] Even apart from the element that there be actual or potential safety significance, the Enforcement Policy sets a very high threshold of factual proof for individual enforcement actions. This high standard has not been met in the present case, as will be discussed below.

The high standard for enforcement actions involving individuals also inherently recognizes that it is often difficult to properly attribute fault to an individual acting within a licensed environment which contemplates the application of judgment. In the long term, the effect of an enforcement regime which punishes judgments made in good faith could lead to diminished morale and difficulty in recruiting licensed personnel. This would ultimately reduce assurance of public health and safety. The Company believes that these general perspectives should also be kept in mind when considering the events at VEGP on October 12-13, 1988.

2. Messrs. Bowles and Cash Lacked the Necessary State-of-Mind Requisite to a Willful Violation.

The single most important fact respecting the activities of Messrs. Bowles and Cash is that they were unaware of the applicability of Tech. Spec. § 3.4.1.4.2 when chemicals were added to the Chemical Mixing Tank at 4:00 a.m. CT on their Night Shift.[13] It was only when personnel from the following Day Shift

---

[12]Similarly, the examples provided in Enforcement Policy Section V.E. of cases where individual enforcement might be appropriate consistently involve either "willfulness" or some gross disregard for responsibilities. The latter include instances of inattention to duty or falsification of records, not relevant to the present facts.

[13] The NRC June 3, 1991 Demand for Information sent to Mr. Cash suggests that he was involved in chemical addition activities on "four occasions." It is important to make clear that neither Mr. Cash nor Mr. Bowles were involved in the three chemical additions made by the Day Shifts of October 12 and 13,

brought the matter to their attention (in the 5:07 to 5:33 a.m. CT time frame), that Messrs. Cash and Bowles recognized the possible applicability of the Tech. Spec. The only relevant overt act taken by either of them after this recognition was the late log entry, which is not in question here.

Messrs. Cash and Bowles lacked the state-of-mind requisite to a finding that they either intentionally violated or carelessly disregarded Tech. Specs. They could not have been carelessly disregarding Tech. Spec. § 3.4.1.4.2 when they were unaware of its applicability. That is, clearly they did not understand that they had responsibilities regarding Tech. Spec. § 3.4.1.4.2 and, therefore, they did not know, or even consider, the required actions. They were not "plainly indifferent" to the Tech. Spec. See Alabama Power Co., 584 F.2d at 752. In fact, given that they were proceeding by procedure to implement a pre-planned evolution, and based on their training and guidance at the time, it cannot be said that they should have recognized the applicability of the Tech. Spec.

The primary factor in Mr. Cash's and Mr. Bowles' lack of recognition was inadequate training and guidance respecting the Loops Not Filled condition of Mode 5.[14] In October 1988, the operators received little or no training on the boron dilution accident with the RCS in the Loops Not Filled condition. Consequently, many VEGP operators understood the Loops Not Filled condition to mean the RCS water level when the RCS had been drained down to below the "top of the hot leg," or, in the case of Mr. Cash, below the "top of the loops." However, when primary water was displaced from the steam generator tubes (which, ironically, causes the RCS water level to rise), the unit was technically in the Loops Not Filled condition according to the

---

1988, which were the occasions when chemicals were actually injected into the RCS. Messrs. Bowles and Cash only supervised the addition of chemicals to the Chemical Mixing Tank on one occasion relevant to this matter, i.e., the Night Shift of October 11-12, 1988.

[14] Significantly, the VEGP operators' general lack of understanding of the "Loops Not Filled" and "Loops Filled" conditions was observed by the NRC in 1989 when it reviewed a VEGP LER associated with a February 1989 VEGP Unit 2 violation of Tech. Spec. § 3.4.1.4.2. See NRC Inspection Report Nos. 50-424/89-14 and 50-425/89-15, dated June 15, 1989, attached as Exhibit 15, at p. 26. That violation occurred when the Unit 2 operators, who believed that filling the RCS above the loops up to the reactor vessel flange level constituted "Loops Filled," released a clearance from the RMWST discharge valves, opened the valves and left them open for four hours with the RCS in the Loops Not Filled condition.

..en-current Westinghouse analysis. See discussion in Section ...

... 1988 ... was only rudimentary guidance available ... in the Control Room respecting RCS water levels at ... ctories. At the time of the 1R1 outage, plant ... accordance with their training -- attuned to ... (versus Loops Not Filled) and associated ... at ... RCS water levels due to industry events and ... The operators used the term "Mid- ... referring to the condition during Cold Shutdown ... level had been drained down to a level at or ... above the centerline of the RCS hot-leg piping, i.e. 188' ... minimum RCS water level during the RCS drain-down procedure. See, e.g., Exhibit 6, § D4.2.13.a(11), at p. 30. The operators did not generally equate Mid-loop with a specific elevation and some operators equated it with Loops Not Filled, including Messrs. Cash and Bowles.[16]

When Messrs. Cash and Bowles came on shift on October 11, 1988, the Day Shift had already completed Section D4.2.14 of VEGP Procedure 12006-C, Rev. No. 9 (Exhibit 6), which requires that

---

[15] As described more fully in Section III.E, herein, today there is a considerable amount of training provided to the VEGP operators concerning Tech. Spec. requirements, including the Loops Not Filled condition. Also, GPC has taken action since October 1988 to clearly define the Loops Not Filled condition. On February 22, 1989, the Operations Manager, Mr. W. F. Kitchens prepared a "Tech. Spec. Interpretation," addressing the matter, attached as Exhibit 16. That interpretation was issued in response to the February 1989 VEGP Unit 2 violation described in footnote 14 above. Further clarification was developed on March 30, 1990 based on data obtained from Westinghouse. See Tech. Spec. § 3.4.1.4 Interpretation, dated March 30, 1990, attached as Exhibit 17.

[16] Since 1988, guidance available in the Control Room to assist the operators during RCS drain-down and Mid-loop activities has evolved into an elaborate series of drawings and charts. For a full discussion of the evolution of VEGP operator guidance concerning RCS water levels at reduced RCS inventories, see Attachment 2. GPC observes that potential confusion of operators with respect to Tech. Specs. applicable to outage conditions and modes has recently been identified as an industry-related issue. See NRC Memorandum from Gary Holahan, dated May 16, 1991, and certain of his comments to the NRC Commissioners on June 1?, 1991, both attached as composite Exhibit 18. In the case of VEGP operators, the Mid-loop condition had received emphasis in training to a far greater extent than the Loops Not Filled condition.

the RMWST discharge valves be closed, locked and tagged.[17] GPC is of the opinion that completion of Section D4.2.14 during the prior Day Shift by Mr. Gasser is likely the principal reason why Mr. Gasser was the one who later raised a question concerning the Tech. Spec.

Another institutional factor contributing to this incident was inadequate review of procedures during outage planning. A detailed description of the planning process for the 1R1 outage relevant to the chemical addition evolution is contained in Section III.D, herein. In summary, the procedures which Messrs. Bowles and Cash were following failed to identify any conflict with Tech. Spec. § 3.4.1.4.2 because, to the VEGP personnel who prepared those procedures as well as to others participating in the outage planning process, it was not clear that a conflict existed. Only one procedure (49006-C, Rev. No. 0) directly addressed at which point during the RCS drain-down process ("Mid-loop") the chemical cleaning was to be performed. That procedure was prepared and approved by the Health Physics and Chemistry Department and was not reviewed by the Operations, or any other, Department. The procedure addressing the specific valve manipulations required for the chemical addition (13007-1, Rev. No. 2) failed to specify at what RCS water level the procedure was permitted to be performed, although the procedure appears to contemplate that it would be performed with Loops Filled.[18]

Based on the foregoing, when it came time to perform the chemical addition evolution on their shift, Messrs. Cash and Bowles had no reason to suspect that there was any conflict between the Tech. Spec. and the pre-planned and scheduled chemical cleaning. They were performing the evolution pursuant to approved procedures and simply did not spot the problem before the shift turnover, when the Day Shift personnel raised the issue. Additionally, Messrs. Cash and Bowles were assisted by, and had delegated the activity to, a Support Shift Supervisor, Mr. Ryan, who approved the Functional Test Form allowing temporary lifting of the clearance on three of the RMWST discharge valves (Nos. 176, 177 and 181), and who supervised the

[17] As discussed in the NRC June 3, 1991 Demand for Information, Section D4.2.14 is included in the procedure pursuant to Tech. Spec. § 3.4.1.4.2, although the water level associated with that step (about 219 feet) was much higher than the "top of the hot leg," the level most operators equated with Loops Not Filled at the time.

[18] The procedure did not expressly provide for opening Valve 177, which is normally open during Loops Filled. In October 1988, this valve was opened pursuant to the Functional Test procedures.

valve manipulations pursuant to the applicable procedure (13007-1, Rev. No. 2). Even Mr. Ryan, a licensed Senior Reactor Operator, who was in the best position to spot any potential conflict, did not recognize that there was a conflict with the Tech. Spec. Furthermore, to GPC's knowledge, no one else on that shift spotted the conflict or raised a question concerning the Tech. Spec. Moreover, considering the training and procedures provided at the time, it cannot even be said that Messrs. Bowles and Cash should have known that the Tech. Spec. was applicable. Therefore, no willful violation occurred.

3. Mr. Kitchens' Interpretation of Tech. Spec. § 3.4.1.4.2 was Reasonable and in Good Faith.

Mr. Kitchens did not willfully violate the Tech. Specs. because his actions at the time do not evidence that he either (1) intended to violate the Tech. Specs., or (2) proceeded in careless disregard of the Tech. Spec. requirements. On the contrary, based on a review of the facts, GPC finds that he conducted a reasonable inquiry and proceeded in good faith under the circumstances. The Company believes that the conclusion Mr. Kitchens reached at the time was reasonable, even if incorrect based on present-day NRC guidance. However, even if the NRC finds that Mr. Kitchens violated the Tech. Spec., it should conclude that his actions did not rise to the level of a "willful" violation of Tech. Specs. as that term has been construed by the NRC and others. Enforcement action against Mr. Kitchens individually is particularly inappropriate when, in accordance with the Enforcement Policy, such action is to be taken only when the NRC finds "little doubt" that he "knew, or should have known," that his actions violated the Tech. Spec.

Mr. Kitchens' review was conducted carefully and openly. When he was first approached by Mr. Hopkins, Mr. Kitchens placed the chemical cleaning evolution on hold so that he could take the time to perform a careful review of the Tech. Spec. and its bases. The delay in the scheduled evolution was raised during the outage status meeting that morning. He reviewed Tech. Spec. § 3.4.1.4.2 and its Tech. Spec. Bases and he reviewed the FSAR. Before reaching a conclusion, he also consulted with Mr. Hopkins and with his Deputy Manager of Operations, Mr. Marsh, a more experienced operations manager. Following his decision, he also discussed the matter with the VEGP NSAC Manager, Mr. Swartzwelder, who was also an experienced senior reactor operator.

Mr. Kitchens knew that voluntary entry into Tech. Spec. LCOs was a common practice in the industry and at VEGP, particularly for maintenance purposes, provided that there was compliance with the Action Statement in accordance with Tech. Spec. §§ 3.0.1 and 3.0.2. Such voluntary entries are clearly permitted in the case of Tech. Spec. Action Statements which provide a specific time period, such as in hours, before certain actions are required to be performed. However, voluntary entry into Tech. Spec. Action Statements which require immediate action was unusual and was not an established practice. Mr. Kitchens was aware of no guidance document from the NRC that prohibited voluntary entry into an LCO which required immediate action.[19] In these circumstances, Mr. Kitchens, who was the highest-ranking GPC employee holding a VEGP Senior Reactor Operator's license, proceeded to determine the intent of Tech. Spec. § 3.4.1.4.2 so he could make an informed decision.

The term "immediate" was not defined in the Tech. Specs. Mr. Kitchens understood it to mean "without undue delay" under the circumstances, although not necessarily the very next action performed. Furthermore, Mr. Kitchens' experience was that an LCO requiring "immediate" action inherently allowed some finite time for action. Mr. Kitchens recalls that, in June 1987, VEGP experienced an entry into an LCO requiring immediate action concerning the Digital Rod Position Indication ("DRPI") system and the NRC Resident Inspector at the time, Mr. Roy Schepens, then concurred with GPC's decision to first determine the cause of the DRPI failure before completing the immediate action pursuant to the LCO Action Statement.[20] Therefore, Mr. Kitchens had reason to equate an LCO requiring an immediate action with an LCO providing an express time period.

Prior to deciding that entry into the LCO was allowed, Mr. Kitchens also specifically reviewed the Tech. Spec. Bases and other documents to assure that the action would comply with the safety underpinnings of the Tech. Spec. The Bases of Tech. Spec. § 3.4.1.4.2 indicated to Mr. Kitchens that the purpose of that Tech. Spec. was to prevent an uncontrolled boron dilution of the RCS. Mr. Kitchens and Mr. Hopkins believed that the intent of the Tech. Spec. (i.e., an uncontrolled boron dilution event)

---

[19] No such guidance from the NRC existed. As discussed in detail in the Section III.B.5 herein, the Company believes that reasonable minds can differ as to whether voluntary entry into Tech. Spec. § 3.4.1.4.2 was permissible in October 1988.

[20] Following that event, GPC revised the relevant VEGP response procedure (17010-1) to direct the operators to place the DRPI system in the "Data A" channel or the "Data B" channel <u>before</u> taking the Tech. Spec. "immediate" action to manually trip the reactor. The NRC has indicated its concurrence with that revised procedure by virtue of the fact that it closed its review of the LER associated with the event based on the procedure revision. <u>See</u> Inspection Report No. 50-424/87-60, dated December 17, 1987, Report Details § 4.b(3)(p), at p. 12, attached as Exhibit 19.

would be met if the opening of the valves was performed under strict administrative controls and with clear time limits.[21]

Mr. Kitchens reviewed FSAR § 15.4.6 and concluded that the boron dilution accident had been analyzed for the Loops Not Filled condition of Mode 5 and that 15 minutes was available for the operator to respond. That conclusion is understandable given that portions of FSAR § 15.4.6, as it existed in October 1988, indicated that an analysis of Mode 5 had been performed and that adequate operator response time was available. (At that time, FSAR § 15.4.6 was a confusing patchwork of Amendment 17 (July 1985), which indicated that Mode 5, including the Loops Not Filled condition, was analyzed and that adequate operator response time was available without administrative controls, and Amendment 30 (December 1986), which attempted to describe that, as in the case of Mode 6, administrative controls were necessary to lock the RMWST discharge valves closed in the Loops Not Filled condition of Mode 5. A more detailed discussion of the evolution of FSAR § 15.4.6, as well as the NRC Safety Evaluation Report § 15.4.6, is included as Attachment 1.)

Mr. Kitchens also reviewed FSAR § 9.3.4.1.2.5.14 which stated that one purpose of the Chemical Mixing Tank was to facilitate the addition of chemicals to "clean-up" the RCS <u>during refueling shutdowns</u>. A copy of the October 1988 version of FSAR § 9.3.4.1.2.5.14 is attached as Exhibit 20.

Mr. Kitchens and Mr. Hopkins spoke to Mr. Marsh, who was a more experienced operations manager than either of them. When they questioned him about the term "immediate" as used in Tech. Spec. Action Statements, they understood him to say that the term had been interpreted at another facility (believed to be San Onofre) to mean that the operator had 15 minutes to act.[22] This

---

[21] The Company notes that NRC Generic Letter 91-08, "Removal of Component Lists from Technical Specifications," dated May 6, 1991, identifies acceptable administrative controls for opening locked or sealed closed containment isolation valves which are consistent with the administrative controls utilized during the VEGP chemical addition evolution on October 12-13, 1988.

[22] Mr. Marsh has informed GPC that he may have addressed the "immediate" time duration associated with "operator action" compensatory for automatic action, as contrasted with "immediate" as used in Tech. Spec. § 3.4.1.4.2. Mr. Marsh has no vivid recollection of the advice he gave, but has the highest regard for the integrity of Messrs. Hopkins and Kitchens and does not question their recollections. Further, Mr. Marsh is presently of the opinion that (1) an interpretation of Tech. Spec. § 3.4.1.4.2 is a grey area, (2) no clear NRC guidance has been provided relative to the "immediate" issue, and (3) manipulation of the

further confirmed Mr. Kitchens' conclusion that the LCO allowed a time for action, and thus could be entered voluntarily.

Mr. Kitchens also performed a simple calculation and determined that, based on an RCS concentration of 780 ppm and the RMWST discharge valves' flow rate of 3.5 gpm (specified in the FSAR), there would be an insignificant amount of boron dilution for the planned addition. Thus, Mr. Kitchens concluded not only that the Tech. Spec. permitted administratively controlled additions of hydrogen peroxide, but also that no deleterious impact on safety would occur.[23]

The reasonableness of Mr. Kitchens' interpretation is demonstrated by the concurrence of the other licensed operators involved in the event and by findings of those who later reviewed the event. At the time of the event, the licensed operators who were involved in the evolution concurred with the interpretation and proceeded accordingly. No one on-shift raised a concern with entry into Tech. Spec. § 3.4.1.4.2. Following the evolution, Mr. Kitchens and Mr. Hopkins recall that Mr. Swartzwelder, the NSAC Manager, indicated his concurrence with the interpretation. When the evolution was later reviewed by the corporate office, Mr. Jack Stringfellow, a licensing engineer, concluded that the Tech. Spec. had not been violated. Upon further review by the Plant Review Board, all voting members or alternates present concluded and voted that the evolution did not violate the Tech. Specs. Additionally, Mr. George Bockhold, Jr., the plant General Manager at the time, also concurred with Mr. Kitchens' interpretation.

Furthermore, at the time Mr. Kitchens rendered his interpretation, he was not motivated by schedular or economic benefits flowing from the completion of the chemical addition evolution. When he was faced with the decision of whether the scheduled chemical addition evolution was permitted by Tech. Specs., his options were to either proceed with or cancel the scheduled evolution. His decision to proceed resulted in an economic cost to GPC due to its effect of lengthening the critical path schedule. There was, however, a safety benefit which accrued to GPC and VEGP outage workers in that the chemical addition was designed to, and did in fact, reduce the

---

RMWST discharge valves in Mode 5 with Loops Not Filled would not violate the Tech. Spec., although it is "not a good idea."

[23]Mr. Kitchens' calculation was not intended as a substitute for the FSAR § 15.4.6 analysis of the boron dilution accident. Indeed, he had concluded that such an analysis already existed for the Loops Not Filled condition of Mode 5. His calculation was a prudent operator check intended to ensure that there would be a negligible effect on boron concentration, and, therefore, reactor criticality.

occupational radiation exposure which the outage workers would have otherwise received without the evolution. A more detailed discussion of the costs and benefits flowing from the chemical addition evolution is included in Attachment 3.

Based on the foregoing, the circumstances surrounding the October 12-13, 1988 chemical addition evolution establish that Mr. Kitchens made a good faith, reasonable attempt to determine, understand and comply with, NRC requirements. The facts do not support a finding that Mr. Kitchens "willfully" violated Tech. Spec. § 3.4.1.4.2, as that term has been construed by the NRC and the courts. Rather, the facts evidence that there is, at a minimum, substantial doubt that he "knew or should have known" that his interpretation violated the Tech. Spec. His experience told him that his interpretation was reasonable and later reviews confirmed his interpretation. Indeed, as will be discussed later herein, the Company believes that reasonable minds can differ as to whether the voluntary entry into Tech. Spec. § 3.4.1.4.2 was permissible in 1988. Furthermore, there was no schedular or economic motivation for Mr. Kitchens to make the decision he made. Therefore, enforcement action against Mr. Kitchens individually is inappropriate under these circumstances as the Enforcement Policy threshold that there be "little doubt that the individual . . . knew, or should have known, the required actions" is clearly not met.

4. The Chemical Addition Evolution Lacked Safety Significance.

As discussed above, the Enforcement Policy (at Section V.E.) also provides that enforcement actions involving individuals should only be taken where the alleged improper actions have actual or potential safety significance. In the present case, such safety significance is minimal. (This is, of course, also a factor for the NRC to keep in mind when considering any enforcement action against the Company regarding these events.)

On November 14, 1989, Westinghouse completed an analysis of GPC's proposed Tech. Spec. change to allow opening of the RMWST valves for short periods of time during Modes 5b and 6 for purposes of chemical addition. <u>See</u> Westinghouse letter, J.L. Tain to C.K. McCoy, dated November 14, 1989 (with attached Safety Evaluation No. SECL 89-943), attached as Exhibit 21. The analysis concludes that, while the evolution was not then analyzed in FSAR § 15.4.6, the proposed change (1) did not involve an "unreviewed safety question," as that term is defined in 10 C.F.R. § 50.59, and (2) met the NRC SRP § 15.4.6 criteria since a minimum of 15 minutes (from receipt of the high flux at shutdown alarm) for operator action was available to mitigate an accident during Mode 5b and 30 minutes was available during Mode 6. <u>See</u> Exhibit 21 at p. 1. The Westinghouse analysis also concluded that chemical addition during Modes 5b and 6 did not violate the plant's licensing basis acceptance criteria. See Exhibit 21 at p. 2. Not only does the Westinghouse analysis support the conclusion that the chemical addition evolution was not reportable under the second and third criteria of 10 C.F.R. § 50.73(a)(2)(ii), but it clearly demonstrates that the evolution lacked safety significance in terms of the boron dilution accident.

On February 20, 1990, the NRC granted a GPC November 21, 1989 application to amend the VEGP Tech. Specs. to allow opening of the RMWST discharge valves for short periods of time during Modes 5b and 6 to add chemicals. See Issuance of Amendment No. 28 to Facility Operating License NPF-68 and Amendment No. 9 to Facility Operating License NPF-81 - Vogtle Electric Generating Plant, Units 1 and 2 (TACs 75320/75321), dated February 20, 1990, attached as Exhibit 22. The NRC Safety Evaluation attached to the license amendments concludes that GPC's November 21, 1989 submittal used conservative assumptions, that the NRC Standard Review Plan acceptance criteria had been met or exceeded, and that the proposed Tech. Spec. amendment will not have any adverse affect on safety. See Exhibit 22, Safety Evaluation at p. 2.

On August 16, 1991, Westinghouse completed an analysis, at the request of GPC, of the actual effect of the chemical addition evolution given the boron concentration of the RCS at the times of the additions on October 12 and 13, 1988. The Westinghouse analysis concludes that, given a boron concentration of 774ppm at 7:00 a.m. CT on October 12, 1988, when the RMWST discharge Valve 176, 177 and 181 were opened, over 48 hours of flow through those valves would have been required before reaching criticality (nearly nine hours of flow from the initiation of the high flux at shutdown alarm would have been necessary). With respect to the chemical additions performed on October 13, 1988, approximately twice those times (i.e., approximately 96 hours and 18 hours, respectively) would have been required before reaching criticality. A copy of the Westinghouse analysis is attached as Exhibit 23.

Considering the 15 minute acceptance criteria from NRC SRP § 15.4.6, the Westinghouse analysis demonstrates that there was minimal safety significance associated with the chemical addition evolution. Furthermore, even if the operators opening the valves had allowed the flow to run continuously through the valves uninterrupted, within 24 hours a shutdown margin calculation would have been performed and compared to chemistry samples of the RCS taken, and the dilution of boron concentration would have been discovered, the source identified and the valves closed.

5. Reasonable Minds Can Differ as to Whether, in 1988, Voluntary Entry into the Tech. Spec. § 3.4.1.4.2 LCO was Permissible.

The NRC's June 3, 1991 Notice of Enforcement Conference and Demand for Information to GPC suggests that the wording of VEGP Tech. Spec. § 3.4.1.4.2 "is exceptionally clear and not open to any interpretation that would allow the intentional manipulation to the open position of the [RMWST discharge] valves with the plant in the specified condition." The Company vigorously disagrees with this statement based on the following facts which demonstrate that the Tech. Spec. is not exceptionally clear. Rather, the issue of voluntary entry into Tech. Spec. LCOs, and specifically those Tech. Spec. LCOs requiring immediate action, is an evolving industry issue for which NRC guidance was lacking in 1988. In this context, the issue before Mr. Kitchens was one where reasonable minds could certainly differ.

It has been suggested that the use of the words "shall be closed and secured in position" in the LCO for Tech. Spec. § 3.4.1.4.2 may have led the NRC to its tentative conclusion that the Tech. Spec. is "exceptionally clear" so as to prohibit the voluntary entrance into the LCO. The Company believes it is unreasonable to draw such a conclusion from the LCO wording in light of both the historical context and the industry experience in applying other Tech. Specs. A host of Tech. Spec. LCOs use similar "shall" wording and yet the NRC has expressly countenanced as permissible the voluntary entry into a number of those LCOs. For example, VEGP Tech. Spec. § 3.5.2 states that, during Modes 1, 2 and 3:

> Two independent Emergency Core Cooling Systems (ECCS) subsystems <u>shall</u> be OPERABLE with each subsystem comprised of: (a) One OPERABLE centrifugal charging pump, (b) One OPERABLE Safety Injection pump, (c) One OPERABLE RHR heat exchanger, (d) One OPERABLE RHR pump, and (e) An OPERABLE flow path... [emphasis added].

As NRC is well aware, VEGP operators perform PM on the components listed above during Modes 1, 2 and 3.

Another example is VEGP Tech. Spec. § 3.6.3 which states that, during Modes 1, 2, 3 and 4, "[t]he containment isolation valves <u>shall</u> be OPERABLE" (emphasis added). In this case, as NRC knows, the VEGP operators open the valves under administrative controls during Modes 1, 2, 3 and 4 to perform maintenance or testing, which, in some cases, renders the valves inoperable.

With respect to voluntary entry into Tech. Spec. LCOs generally, NRC provided a position in a January 1, 1982 interpretation which stated:

The NRC endorses Voluntary Entry into the Action Statement Conditions and has structured the [standard] TS to permit the licensee to exercise judgment within the latitude permitted by the Action Statement language in the TS.

See NRC Standard Technical Specification Interpretation, Section 3.0, "Voluntary Entry Into Action Statements," dated January 1, 1982; see also NRC Memorandum from B. K. Grimes to S. E. Bryan, dated June 13, 1979 (both documents are attached as composite Exhibit 24).

In December 1990, the NRC notified the Institute of Nuclear Power Operations ("INPO") of a concern it has with licensees' voluntary entry into Tech. Specs. during power operations for purposes of performing preventive maintenance ("PM"). See NRC letter from Mr. James H. Sniezek to Mr. Kenneth A. Strahm of INPO, dated December 27, 1990, attached as Exhibit 25. This concern had not been addressed in any guidance available to operators prior to October 1988; moreover, it reflects the state of industry practice as late as December 1990 and the NRC's evolving regulatory position. This perspective is important in assessing the actions of GPC and its operators in 1988.

Further guidance regarding voluntary entry into Tech. Spec. Action Statements was only subsequently provided in April 1991 in the NRC Inspection Manual, Part 9900, "Voluntary Entry Into Limiting Conditions For Operation Action Statements To Perform Preventive Maintenance," attached as Exhibit 26. The purpose of this guidance is, "[t]o provide a set of safety principles for guiding the performance of preventive maintenance (PM) at licensed nuclear reactor facilities when the performance of the PM requires rendering the affected system or equipment inoperable (on-line PM)." The NRC Staff notes that although these principles primarily apply to PM during power operation, they also apply to PM on equipment that must be operable during shutdown evolutions such as fuel handling or Mid-loop operation. This Inspection Manual interpretation allows intentional entry into an LCO Action Statement if maintenance is completed and operability restored within the time specified in the Action Statement "allowed outage time" ("AOT"). According to NRC, if this criterion is satisfied, "[i]ntentional entry into an action statement of an LCO is not a violation of the TS (except in certain cases, such as intentionally creating a loss of function situation or entering LCO 3.0.3)." See Exhibit 26 at Section B (emphasis added). Even this 1991 guidance does not expressly prohibit the voluntary entry into LCOs with Action Statements requiring immediate action. Also, based on the discussion below concerning the meaning of the term "immediate" as used in the Tech. Specs., one could reasonably conclude that "immediate" is equivalent to an AOT.

The NRC observed in the Inspection Manual that it had not established (official) guidance on taking equipment out of service to perform PM until 1991. Again, in 1988, the only clear NRC guidance available to VEGP operators on the question of voluntary entry into Tech. Spec. LCOs indicated that such entry was permissible provided the Action Statement was followed. The NRC had indicated, as early as August 1987, that the voluntary entry into Tech. Spec. § 3.0.3 is prohibited. See Technical Specification Improvement Program Highlights, dated August 1987, attached as Exhibit 27, at p. 2. However, the NRC had not provided any equally clear guidance on an entry such as that considered by Mr. Kitchens. In light of this silence, the Company considers that his good faith consideration of the intent of the Tech. Spec. can only be regarded as reasonable.

A review of the historic development of the use of the term "immediate" in the Tech. Specs. is also enlightening. There has long been a presumption that the term "immediate" as used in Action Statements inherently involves some period of elapsed time. Thus, the difference between a Tech. Spec. Action Statement using the term "immediate" and one with an expressed AOT is not as great as the NRC now apparently perceives it to be.

For example, during development of the Westinghouse Standard Technical Specifications ("W-STS"), an ad-hoc committee of utilities (approximately 5 utilities scheduled to receive the first W-STSs), held discussions with the NRC in the mid-70's. Mr. George Hairston, III, currently GPC's Senior Vice President - Nuclear Operations (then Operations Supervisor at Alabama Power Company's Plant Farley), participated in those discussions along with Mr. Charles C. Little, then a project manager for Westinghouse. Both Mr. Hairston and Mr. Little recall that the definition of the term "immediate" as used in Action Statements was of concern to the group and the issue was debated "long and hard" with the NRC. Both men remember that the group recommended to the NRC that the term "immediate" should be replaced throughout the W-STS with a specific time period of approximately 10 to 20 minutes. "Immediate" was never intended to connote "no time for action" (i.e., no AOT). Significantly, Mr. J. M. McGough, who from 1973 to 1978, conceived, developed and implemented the Standard Tech. Spec. program for the NRC, now recalls those discussions as well. Mr. Little and Mr. McGough have provided the Company with written statements concerning those discussions which are attached as composite Exhibit 28.

Mr. McGough recalls that one of the objectives of the Standard Tech. Spec. program was to ensure that operators, faced with a situation on-shift at 3:00 a.m., had clear and unambiguous Tech. Specs. to follow. Toward that end, Mr. McGough recalls, it was recognized that the term "immediately" was impossible to define given the varying degree of severity the Action Statements were being required to cover. Therefore, the term "immediately" was replaced in some of the Standard Tech. Spec. sections by a series of time-dependent Action Statements tailored to fit the severity of the particular situations being addressed. This further illustrates that action statements requiring immediate action are not fundamentally different from those with AOTs.

In 1977, an internal NRC memorandum also discussed the meaning of the term "immediate" as used in some Tech. Specs. which required immediate testing of a system upon the failure of its redundant counterpart. See NRC Memorandum from J. H. Sniezek to G. Fiorelli, dated May 20, 1977, attached as Exhibit 29. Mr. Sniezek advised that a specific time period of four hours could not be generally applied in that case because the term "immediate" could be interpreted differently depending upon the "cause of the system failure" (i.e., the "urgency to conduct the test"). He concluded by stating that "for the present, the NRC will rely on the technical judgment of the NRC inspection staff on a case-by-case basis." Mr. Kitchens' actions in 1988 to assess the intent of Tech. Spec. § 3.4.1.4.2 were not inconsistent with this conclusion.

Since October 1988, the NRC and industry representatives have discussed proposed Standard Tech. Specs. in connection with the MERITS program. Some of those discussions have focused on the meaning of the term "immediately" and proposals have been made by the Westinghouse Owners Group to further replace the word "immediately" with a specific period of time. Two examples, which are particularly relevant to this enforcement action, are discussed below.

The proposed MERITS program Standard Tech. Spec. concerning boron concentration during refueling operations specifies the following LCO:

> The boron concentration of all filled portions of the Reactor Coolant System, the refueling canal, and the refueling cavity shall be maintained within the limit provided in the CORE OPERATING LIMITS REPORT.

The Action Statement of this Tech. Spec. provides that with the boron concentration outside the limit specified in the LCO, the following "Required Actions" are to be taken within the specified "Completion Times":

	REQUIRED ACTION	COMPLETION TIME
A.1	Suspend CORE ALTERATIONS and positive reactivity additions.	15 minutes

AND

A.2.1 Initiate boration to restore concentration.	15 minutes
AND	
A.2.2 Continue action as required in A.2.1.	Until boron concentration is restored

The corresponding VEGP Tech. Spec. provides that when the specified boron concentration is not met, "immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to ...." See VEGP Tech. Spec. § 3.9.1 (emphasis added). Therefore, industry representatives have recognized that the term "immediately" as used in VEGP Tech. Spec. § 3.9.1 can and should be replaced with a specific time interval, in this case, 15 minutes.

Another particularly relevant example from the MERITS program proposals is the Tech. Spec. concerning Unborated Water Source Isolation Valve positions during refueling operations. The MERITS Tech. Spec. LCO provides:

> Each valve used to isolate unborated water sources shall be secured in the closed position. NOTE: Valves may be opened during planned boron dilution or make-up activities.

The Action Statement provides the following Required Actions and Completion Times when one or more valves are not secured in the closed position:

	REQUIRED ACTION	COMPLETION TIME
A.1	Suspend CORE ALTERATIONS	15 minutes
AND		
A.2	Secure valve in closed position.	1 hour
AND		
A.3	Perform SR 3.8.1.1.	4 hours

In contrast, the corresponding VEGP Tech. Spec. provides that when the unborated water source isolation valves are not closed and secured in position during refueling operations, "immediately close and secure in position." See VEGP Tech. Spec. § 3.9.1 (emphasis added).[26]

The latest draft of the MERITS Standard Tech. Specs. contains the following explanation of the term "immediately" when used as a Completion Time:

> In some cases "Immediately" is used as a Completion Time. In this case, the Required Action should be pursued without delay and in a controlled manner.

As stated earlier, the VEGP Tech. Specs. do not contain a definition of the term "immediately." The proposed MERITS definition of the term "immediately" is inconsistent with the experience at VEGP concerning the DRPI Tech. Spec. which was expressly reviewed and approved by the NRC Resident Inspector at the time. See footnote 20 and accompanying text, above. Further, the above construction appears to conflict with the Tech. Specs. of a number of 1970s vintage operating reactors which already contain a definition of the term "immediate." GPC's Plant Hatch Unit 1 is one of those plants. The Hatch 1 Tech. Specs. state that the term "immediate" means

> the required action shall be initiated as soon as practicable, considering the safe operation of the Unit and the importance of the required action.

See Hatch 1 Tech. Spec. p. 1.0-2, initially issued in August 1974, attached as Exhibit 30. Identical definitions of "immediate" are also contained in the Tech. Specs. of Dresden 2 (December 1969), Pilgrim (June 1972), Duane Arnold (February 1974) and Browns Ferry 3 (August 1976). The Company considers the Hatch 1 definition to be synonymous with an interpretation of

---

[26] The Company understands that the Westinghouse Owners Group proposals discussed above have not been incorporated into the MERITS Standard Tech. Specs. due to NRC's desire to maintain consistency among the various owners groups. This ongoing dialogue between NRC and the industry may be the appropriate forum to address (1) the evolving industry issue of voluntary entry into LCOs with Action Statements which do not contain AOTs, and (2) the meaning of the word "immediately" as contained in Tech. Specs.

"without undue delay under the circumstances," and that it does not mean "the very next action which the operator performs."[25]

An interpretation that the term "immediate" connotes a short duration is consistent with the safety analyses which form the bases of the Tech. Specs. For example, with respect to Tech. Spec. § 3.4.1.4.2, the NRC's Standard Review Plan § 15.4.6 requires that 15 minutes be available for operator action following a "high flux at shutdown" alarm in order to mitigate a boron dilution event during Mode 5 (30 minutes in the case of Mode 6). See Attachment 1, Exhibit D.

The present day potential for operators throughout the industry to interpret Tech. Specs. so as to permit voluntary entry into LCOs with "immediate" Action Statements (based on the "intent" of the Tech. Spec.) is demonstrated by a Tech. Spec. interpretation which was made at TVA's Sequoyah facility earlier this year. See TVA letter to NRC, dated April 10, 1991, (transmitting LER 50-328/91003) and NRC Inspection Report Nos. 50-327/91-06 and 50-328/91-06, dated April 25, 1991, attached as composite Exhibit 31. The Company understands that, similar to the VEGP chemical addition evolution, a TVA operator construed the term "immediate" in a Tech. Spec. Action Statement to permit voluntary entry under administrative controls (and by procedure) into the Action Statement for a short period of time (in that case for 13 minutes) to perform maintenance. Although the particular Sequoyah Tech. Spec. in question contained a phrase allowing Sequoyah operators two options: "either immediately open the isolation valve or be in HOT STANDBY within one hour and be in HOT SHUTDOWN within the next 12 hours," GPC understands that the Sequoyah operator was applying the "immediate" action option. The Company submits that the actions of the Sequoyah operator -- right or wrong -- during this event demonstrate that other operators can reach a similar interpretation to the one made by Mr. Kitchens on October 12, 1988, even in today's environment.[26]

---

[25] Conversely, the Hatch Unit 2 Tech. Specs. do not contain a definition of "immediate." The Company does not interpret the absence of such a definition to imply that a different definition should be applied at Unit 2. Otherwise, such a result would lead to confusion for dual-unit operators at Plant Hatch.

[26] The Company notes that escalated enforcement action was not taken in connection with the Sequoyah event. Likewise, escalated enforcement action is inappropriate in the case of the October 12-13, 1988 chemical addition evolution. Rather, the NRC should provide additional guidance and purposeful revisions of Tech. Specs. to preclude repetitions of activities which the NRC now views as contrary to requirements.

The term "immediate" has not been used in the Tech. Specs. in a purposeful, consistent manner. This can lead to differing Tech. Spec. interpretations due to operator confusion. The VEGP Tech. Specs. use the term "immediately" in a number of Action Statements where there is not otherwise any AOT. There are also a number of other VEGP Tech. Specs. with Action Statements which do not expressly provide an AOT, but do not use the term "immediately." For example, VEGP Tech. Spec. § 3.9.4 provides an LCO respecting containment penetration isolation during core alterations or movement of irradiated fuel in containment. The associated Action Statement provides:

> With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or movement of irradiated fuel in the containment building [emphasis added].

In contrast, VEGP Tech. Spec. § 3.9.9 provides that the Containment Ventilation Isolation System shall be operable during core alterations or movement of irradiated fuel in the containment. Its associated Action Statement reads:

> With the Containment Ventilation Isolation System inoperable, close each of the Ventilation penetrations providing direct access from the containment atmosphere to the outside atmosphere.

The latter Tech. Spec. Action Statement does not use the term "immediately" and there is no apparent reason for any distinction to be made between the two Tech. Specs. The Company submits that such inconsistent use of the term "immediately" can only (and, in this case, did) lead to operator confusion.

Furthermore, GPC notes the OI investigation and this proceeding in themselves provide further evidence that reasonable minds can differ and have differed on the interpretation of VEGP Tech. Spec. § 3.4.1.4.2. For example, GPC is aware that OI sought guidance from NRR on the interpretive issue and GPC has reason to believe differences in professional opinions have been expressed within the NRC. Also, the duration between the completion of primary OI field investigations (approximately May, 1990) and issuance of the June, 1991 Demands for Information, GPC submits, reflects the fact that the matter is far from clear.

In summary, the Company believes that reasonable minds can differ as to whether voluntary entry into Tech. Spec. § 3.4.1.4.2 was permissible in the October 1988 time frame. The NRC should not bring an enforcement action where, as in this case, the disputed action concerns an evolving generic industry issue. Rather, an appropriate method for resolving this issue would be generic guidance similar to that used by NRC to resolve its other concerns with voluntary entry into LCOs, discussed above.

C. Georgia Power Company Procedures Relating To The Issuance And Control Of Technical Specification Clarifications.

1. The Policies and Procedures in Place at the Time of the Addition of Chemicals on October 12 and 13, 1988.

At the time of the 1R1 outage, VEGP Procedure 10000-C, "Conduct of Operations," Rev. No. 9, attached as Exhibit 32, was in effect. Section 3.11 of that procedure provides guidance concerning the issuance of Tech. Spec. interpretations. It indicates that when an operator determines an immediate interpretation is necessary, he or she could contact any one of four Operations Department management personnel for a verbal interpretation, which would be "followed up by the interpreter with a written request form." See Exhibit 32 at pp. 20-21.

On the Day Shift of October 12, 1988, Messrs. Gasser and Hopkins followed Procedure 10000-C by requesting an interpretation of the Tech. Spec. from Mr. Kitchens. Following his review of Tech. Spec. § 3.4.1.4.2 on October 12, 1988, Mr. Kitchens provided verbal guidance to Mr. Hopkins concerning the addition of chemicals to the RCS. Mr. Kitchens did not believe it was necessary to follow up with a written Tech. Spec. interpretation since a formal Tech. Spec. amendment would be requested for clarification (and was later requested) and there would be no need for such an interpretation prior to the next refueling outage, at which time the Tech. Spec. would have been amended.

2. Current Policies and Procedures.

Since October 1988, the provisions of Procedure 10000-C governing Tech. Spec. clarifications have been revised. See VEGP Procedure 10000-C, Rev. No. 21, attached as Exhibit 33, at § 3.11 and Figure 3. Today, an operator in immediate need of a clarification must contact one of the following three Operations Department management personnel: the Shift Superintendent, the Operations Superintendent, or the Manager of Operations. The clarification will then be given verbally, and may be followed up with a written request form. See Exhibit 33, § 3.11.1, at p. 20. When an immediate clarification is not necessary, the requestor will complete a request form and send it to the Operations Manager.

Unlike the situation in 1988, after a clarification is made, review and concurrence is obtained from the Technical Support Manager, following which final approval is obtained from the Manager of Operations. The Technical Support Manager is responsible for obtaining corporate licensing support or NRC consultation, if deemed necessary, prior to final approval of the clarification by the Manager of Operations. Currently, the Technical Support Manager position is staffed with a licensed Senior Reactor Operator who has also served as the technical assistant to a former NRC Commissioner.

The current version of the Tech. Spec. clarification provisions described above was developed as a result of an observation made during an NRC Special Team Inspection ("STI") of VEGP in August of 1990. That observation, documented in Inspection Report Nos. 50-424/90-19 and 50-425/90-19, dated January 11, 1991, attached as Exhibit 34, noted that a weakness existed in that one individual, the Operations Manager, was responsible for the approval and distribution of Tech. Spec. clarifications. See Exhibit 34, Inspection Details, § 2.1.1.1, at pp. 7-9. GPC's February 8, 1991 response to Inspection Report 90-19 committed to implement the changes described above. During the weeks of June 17 and 24, 1991, NRC Region II inspectors returned to VEGP to review GPC's corrective actions resulting from the STI. They found that Tech. Spec. clarifications were well performed and, with respect to the Tech. Spec. clarification provisions of Procedure 10000-C, GPC's corrective actions were satisfactory. Their conclusions are documented in Inspection Report Nos. 50-424/91-14 and 50-425/91-14, dated July 19, 1991, attached as Exhibit 9, § 3.c., at pp. 5-6.

Additionally, NRC Resident Inspectors at VEGP recently noted a strength in the conservative approach taken by GPC in the evaluation and clarification of Tech. Specs. Specifically, Inspection Report Nos. 50-424/91-05 and 50-425/91-05, dated April 16, 1991, attached as Exhibit 35, found that on three occasions, where GPC found it necessary to clarify the Tech. Specs., GPC's clarifications were "safe and conservative" even though they involved weighing safety and economic factors. See Exhibit 35 at p. 4; see also Exhibit 9, § 2.c., at p. 2.

Also, today there is greater corporate office assistance requested by and provided to VEGP personnel than existed in 1988. When requested by VEGP plant management, corporate licensing personnel are used to research Tech. Spec. clarifications. Additionally, when deemed appropriate, the NRC is contacted concerning proposed Tech. Spec. clarifications. A recommendation is then made to VEGP personnel regarding the Tech. Spec. clarification.

Furthermore, communication between VEGP management and the NRC has improved as noted by the NRC in the most recent SALP Report for VEGP, covering the period October 1, 1989 through September 30, 1990. See NRC Inspection Report Nos. 50-424/90-23 and 50-425/90-23, dated December 10, 1990, attached as Exhibit 36, at p. 5. In many respects this enhanced communication reflects the maturation of VEGP and the recognition that discussions with knowledgeable NRC representatives constitute a valuable resource.

D. The Georgia Power Company Outage Planning Process.

1. Planning for the 1R1 Outage and Development of the Procedures to Add Chemicals to the RCS at the Mid-loop Condition of Mode 5.

In December 1987, the VEGP Outages and Planning organization ("O&P") first identified that chemical cleaning of the RCS would be performed during the 1R1 outage. See Resolution Item Tracking Master Report, dated December 27, 1987, attached as Exhibit 37, sheet 2, item 20. However, it was not until April 14, 1988 that it was decided to perform the chemical cleaning after the RCS had been drained down to the "Mid-loop" level in Mode 5. See Refueling Outage Meeting Minutes (April 14, 1988), dated April 18, 1988, attached as Exhibit 38, at p. 1.

Then, as now, O&P was responsible for planning refueling outages. At that time, O&P was not staffed with a dedicated licensed reactor operator. The VEGP Operations Department participated in the outage and planning process by designating a representative, who was a licensed operator, to attend the outage planning meetings and provide "interface" between the Departments.

The Operations Department representatives in the planning process for the 1R1 outage did not realize that the proposed chemical addition of hydrogen peroxide at Mid-loop conditions required the opening of the RMWST discharge valves. As a result, those representatives did not realize, and, to GPC's knowledge, no one else involved in the outage planning process recognized, that the VEGP Technical Specifications were involved with the chemical addition evolution. This is not to imply that the review effort was inconsequential. As one example, a Tech. Spec. conflict with a containment isolation valve manipulation evolution was identified during the effort. See Exhibit 38 attachment entitled "Resolution Item Tracking - Open Items," at p. 3, Resolution No. 70.

On April 29, 1988, the VEGP Health Physics and Chemistry Department initiated the review of a new procedure, 49006-C, entitled "Health Physics and Chemistry Department Outage Activities." See Procedure Review Request Form ("PRRF") for Procedure 49006-C, dated April 29, 1988 (one sheet) with attached Environmental Evaluation (one sheet) and Safety Evaluation (one sheet), all attached as Exhibit 39. Procedure 49006-C, Rev. No. 0, attached as Exhibit 40, expressly provided that the chemical cleaning evolution would be performed after the RCS had been cooled down to 110°F and drained down to the "Mid-loop" level.

See Exhibit 40, §§ 6.4.4.c and d, at p. 15. When the PRRF was prepared, however, the initiator concluded that the Tech. Specs. were not involved because, he thought, "this level of detail is not in Tech. Specs." See Exhibit 39, sheet 3. As a result, Procedure 49006-C was reviewed and approved within the Health Physics and Chemistry Department and was not reviewed by other departments or by the Plant Review Board. See Exhibit 39, sheet 1.

Two other VEGP procedures were relevant to the chemical addition evolution. First, VEGP Procedure 13007-1, Rev. No. 2, attached as Exhibit 12, provided explicit instructions to the Operations Department concerning valve manipulations to add chemicals to the RCS. That procedure did not specify at what RCS water level the chemical addition was to be performed. See Exhibit 12 at pp. 12-13. However, Procedure 13007-1 apparently contemplated application with the RCS in the "Loops Filled" condition since it did not require the opening of Valve 177 (a valve which is normally open with Loops Filled) when adding water to the Chemical Mixing Tank from the RMWST.

Second, VEGP Procedure 35110-C, Rev. No. 10, attached as Exhibit 41, provided instructions to Chemistry personnel for the addition of chemicals. See Exhibit 41, § 4.11, at p. 14. That procedure provided that, after filling the Chemical Mixing Tank, the chemistry technician was to request the Operations Department to perform the necessary valve manipulations in order to inject the chemicals into the RCS. The procedure did not specify at what RCS water level chemicals could be added.

Based on the foregoing, GPC believes that the conflict between Tech. Spec. § 3.4.1.4.2 and the chemical addition evolution, planned for the Mid-loop condition of Mode 5, escaped recognition by VEGP personnel prior to the 1R1 outage. GPC attributes this oversight to (1) insufficient involvement of the Operations Department or licensed operators in the outage planning process, due, in large part, to the inexperience of VEGP, (2) inadequate inter-departmental review of the chemistry procedure concerning outage activities, due to a failure to follow procedures,[27] and (3) failure to adequately consider potential applications of the procedures in various modes and conditions.

---

[27]GPC has recently briefed VEGP procedure writers concerning VEGP requirements for inter-departmental review of procedures they prepare. This training was a corrective action performed to address an operational weakness concerning inter-departmental review of procedures identified by NRC during the August 1990 STI. See Exhibit 34 at pp. 16-17. During the NRC's follow-up inspection of GPC's corrective actions, that item was closed. See Exhibit 9, § 3.d., at p. 6.

2. Current Outage Planning Process.

The operational experience and expertise of O&P has been strengthened and the depth of review during the outage planning process for potential operational limitations has been increased. Today, O&P is a multi-disciplined and experienced group which prepares and maintains up-to-date outage plans/schedules for planned outages, maintenance outages and forced outages, and maintains long-range schedules. VEGP Procedure 29537-C, Rev. No. 5, attached as Exhibit 42, identifies the organizations, relationships and responsibilities associated with outage planning and scheduling. The following paragraphs summarize the current outage planning process for "planned outages." For further details, see Exhibit 42, § 4.4, at pp. 10-13.

When the scope of the outage is determined and the needed work activities are known, O&P personnel use the Tech. Specs. as limitations for scheduling the day to day activities of the overall outage schedule. Additional factors considered include risk assessment (beyond Tech. Specs. requirements), budgets, contractor support, workload on control room operators and plant operators, manpower resources and material support.

Approximately six months before a planned refueling outage begins, O&P personnel send a preliminary outage schedule to affected departments for input and review. Licensed Senior Reactor Operators from the Operations Department now review the schedule at a detailed level to ensure compliance with Tech. Specs. This is an iterative process between O&P and the Operations Department, or between O&P and other affected departments, as the case may be. The end result is a detailed outage schedule whose activities have been intensely examined.

Reviews are conducted to ensure that needed temporary modifications are identified, ALARA concepts are incorporated, operability issues are addressed, work areas are not congested, and Tech. Spec. compliance can be demonstrated. Special consideration is given to plant configurations resulting in reduced RCS coolant inventory.

As new work is added to the schedule and schedule iterations occur, outage risk management concepts are used to evaluate the overall impact of any reduction of safety system capability. During the development and review process, priority is given to ensuring compliance with Tech. Specs., avoiding LCOs, identifying any mode-constraint LCOs and considering outage risk management concepts (over and above Tech. Spec. compliance) to enhance radiological safety.

Prior to final approval by the plant General Manager, the final outage schedule is reviewed and approved by the Manager of

O&P, the Operations Manager, the Maintenance Manager, the Health Physics and Chemistry Manager, the Engineering Manager, the Technical Support Manager, the Assistant General Manager-Plant Support, and the Assistant General Manager-Operations.

The NRC's review of the VEGP March 20, 1990 operational event is instructive with respect to the pre-October 1988 O&P review efforts. The NRC Incident Investigation Team ("IIT") observed that certain aspects of outage management was a performance shortcoming. Following the March 20, 1990 event, GPC made improvements in its outage management and the NRC noted those improvements in its December 10, 1990 SALP Report on VEGP. See Exhibit 36 at pp. 19-20.

E. Georgia Power Company Policies, Procedures, Practices And Training Respecting Compliance With The VEGP Technical Specifications.

Today, VEGP operators receive specific training concerning the Tech. Specs. including (1) the legal authority requiring Tech. Specs., (2) the five major sections of the Tech. Specs. and their purposes, (3) the detailed format of the Tech. Specs., (4) Tech. Spec. clarifications (VEGP Procedure 10000-C), and (5) Tech. Spec. amendments. See VEGP Training Lesson Plan LO-LP-39201-06-C, "Introduction to Technical Specifications," Rev. No. 6, attached as Exhibit 43. The LCO and surveillance requirements of Tech. Spec. §§ 3.0 and 4.0 are explained during the training, and examples of each are provided. Each current Tech. Spec. clarification is reviewed with the class. See Exhibit 43, §§ II.C.3. and II.D, at pp. 8-11. Hypothetical situations requiring application of the Tech. Specs. are often discussed during operator training and encountered during simulator exercises.

In addition, during requalification training, VEGP operators are provided with (1) periodic updates of significant plant modifications and procedural changes, and (2) information from selected operating events. See VEGP Training Lesson Plan RQ-LP-63107-00, "Requal Current Events," Rev. 0, attached as Exhibit 44. For example, operators are specifically trained in the changes made to VEGP Procedure 12006-C respecting the opening of the RMWST discharge valves and the Tech. Spec. § 3.4.1.4 interpretation of "Loops Not Filled." See Exhibit 44, §§ III.C.1 and III.D.1, at pp. 6 and 7, respectively.

In early 1989, the VEGP "Shift Briefing Book" and "Operations Reading Book" were revised to ensure that all Operations Department supervisors and all reactor operators are aware of the Tech. Spec. requirements for the RMWST discharge valves to be closed and secured in position during the Loops Not Filled condition of Mode 5 and during Mode 6. Also, in 1989, a number of VEGP procedures were revised to add a precaution and limitation which recited the Tech. Spec. requirements that the RMWST discharge valves be closed and secured in position during the Loops Not Filled condition of Mode 5 and during Mode 6, including Procedure Nos. 12000-C (Rev. No. 14), 12001-C (Rev. No. 13), 13007-1 (Rev. No. 3), 13007-2 (Rev. No. 2), 13701-1 (Rev. No. 10) and 13701-2 (Rev. No. 1).

In connection with the specific events of October 12-13, 1988, GPC Vice President-Nuclear (Vogtle), Mr. C. Kenneth McCoy, or the VEGP General Manager, Mr. William B. Shipman, personally contacted the three VEGP Operations Department employees shortly after receipt of the NRC's June 3, 1991 correspondence and reinforced their individual obligations to comply with NRC regulatory requirements, including the Tech. Specs.

VEGP operators' compliance with Tech. Spec. requirements is also addressed by several other means. First, VEGP Procedure 10000-C, "Conduct of Operations," attached as Exhibit 33, expressly charges Operations Department personnel with the responsibility to ensure plant operations are conducted in accordance with the Technical Specifications and approved procedures. See Exhibit 33, §§ 2.2.c., 2.3.a. and 2.5.c., at pp. 2, 3 and 5, respectively. Second, licensed operators are encouraged to be thoughtful and questioning in approaching their day-to-day activities and, when unsure, to seek assistance from Operations Department line management. Access to upper line management by plant personnel is a key component of the philosophy of VEGP management. The plant duty manager (a senior manager on-call 24 hours a day) or Operations Manager are often contacted by shift personnel when questions concerning equipment operability or other issues arise under the Tech. Specs. Third, coaching and decision-making through teamwork is an important technique used by management to ensure operator compliance with Tech. Specs.

The VEGP Operations Department Manager also seeks assistance from the plant and corporate technical and licensing staffs when difficult questions arise. As described in Section III.C above, the VEGP procedure concerning Tech. Spec. clarification has recently been revised to require that all Tech. Spec. clarifications are reviewed by the VEGP Technical Support Department Manager.

VEGP Department Managers routinely observe implementation of Tech. Specs. and plant procedures through the Management Observation Program and day-to-day involvement with plant activities. Also, QA audits and other evaluations provide independent insights to management concerning licensed operators' compliance with Tech. Specs.

Additionally, GPC has a "Positive Discipline Policy" designed to stimulate individual accountability for all aspects of regulatory compliance through the use of (1) oral reminders, (2) written reminders, and (3) decision making leaves, which are used in ascending order. A copy of the current GPC Positive Discipline Policy is attached as Exhibit 45. The Company currently holds all senior reactor operators accountable for compliance with Tech. Specs. and reporting requirements through the annual review of each operator's performance. This process holds individuals as well the collective shift accountable for, among other things, compliance with Tech. Specs. GPC has found this process promotes more open discussions concerning Tech. Spec. compliance.

In February 1989, Mr. Kitchens, as Operations Manager, issued an Operability Policy to all licensed operators which included guidance to ensure strict compliance with Tech. Specs. The policy established responsibilities for interpretation and use of the Tech. Specs. A copy of Mr. Kitchens' memorandum distributing the Operability Policy is attached as Exhibit 46.

Recently, Mr. William Shipman, the VEGP General Manager, issued a memorandum to all Operations Department employees designed to advise them, in a positive way, of the importance of compliance with the Tech. Specs. and the Tech. Spec. clarification procedure. Mr. Shipman's memorandum also advised the operators of certain NRC guidance concerning voluntary entry into Tech. Spec. LCOs and plainly stated that NRC does not consider it appropriate to voluntarily enter LCOs which do not provide a specific AOT. A copy of Mr. Shipman's memorandum is attached as Exhibit 47.

As a general matter, the Company continuously urges and expects Operations Department personnel to conform their activities at all times with the NRC operating license, including the Tech. Specs., and all NRC rules, regulations and orders. The Company recognizes that successful plant operations depend on such compliance. GPC believes this fundamental philosophy is well established in the culture at VEGP.

IV. REASONABLE ASSURANCE EXISTS THAT GEORGIA POWER COMPANY CURRENTLY CONDUCTS AND WILL IN THE FUTURE CONDUCT LICENSED ACTIVITIES IN ACCORDANCE WITH THE VEGP TECHNICAL SPECIFICATIONS AND ALL OTHER NRC REQUIREMENTS.

The Company firmly believes that none of the events surrounding the October 1988 VEGP chemical addition evolution, or any other events at VEGP, should give rise to an NRC concern over GPC's compliance with Tech. Specs. or other NRC requirements. No deliberate violation of Tech. Specs. has occurred and no licensed individual at VEGP has carelessly disregarded the Tech. Specs. Additionally, the events concerning the October 1988 chemical addition evolution were an isolated occurrence, the institutional root causes for which have been identified and addressed.

However, improvements have been made since 1988 as a result of weaknesses identified by GPC and several identified by NRC. Specifically, as discussed in Section III.C, above, GPC's current procedure regarding VEGP Tech. Spec. clarifications has been improved and NRC inspectors have recently found that procedure acceptable. The NRC Resident Inspectors have also recently found that actual Tech. Spec. clarifications made by VEGP Operations Department personnel were safe and conservative. These inspectors have generally expressed their support for the VEGP Operations Department management. In addition, GPC has improved communication between VEGP and the NRC, as well as between VEGP and the corporate office in Birmingham.

As discussed above, GPC has also made significant improvements in outage planning and management and procedure preparation. See Section III.D, above. Those improvements have been noted by NRC inspectors.

Operator training and guidance has also improved considerably since the VEGP 1R1 outage as demonstrated in Section III.E and Attachment 2, respectively.

From a broad perspective, the NRC has recently assessed operations at VEGP and found that VEGP is operated in a safe manner. In August 1990, the NRC conducted a Special Team Inspection at VEGP, including a performance-based evaluation of the Operations Department in order to (1) evaluate the operational philosophy, policies, procedures, and practices of the operating staff and management, and (2) determine if the plant was being operated in a safe manner in accordance with the operating licenses. The inspection team used NRC Inspection Procedures 71707, "Operational Safety Verification," and 71715, "Sustained Control Room and Plant Observation." The inspection team found that the facility was operated in a safe manner in accordance with the requirements of the Facility Operating Licenses. See Exhibit 34 at p. 1. Where specific weaknesses were identified, GPC planned and implemented corrective actions. Following a review of the GPC corrective actions during the weeks of June 17 and 24, 1991, the NRC closed each one of the inspection findings indicating that GPC had adequately addressed the operational weaknesses. See Exhibit 9, §§ 3.a. through 3.k., at pp. 5-9.

V. CONCLUSION.

The information provided in Section III.B, herein, provides substantial evidence that GPC Operations Department personnel did not willfully violate VEGP Tech. Spec. § 3.4.1.4.2 on October 12 and 13, 1988.

The first shift to enter into the Tech. Spec., that of Messrs. Cash and Bowles, was unaware of the applicability of the Tech. Spec. and, therefore, did not have the necessary state of mind requisite to a willful violation. Based on the training, guidance and procedures available to them at the time, it cannot even be said that Messrs. Bowles and Cash should have known that the Tech. Spec. was applicable. (Indeed, in February 1989, different operators on VEGP Unit 2 also failed to recognize the Loops Not Filled condition.) When the issue was raised by the on-coming shift personnel, Messrs. Bowles and Cash made an appropriate entry in the log, documenting their late realization. Because they did not know the Tech. Spec. was applicable, they could not have either deliberately violated the Tech. Spec., or carelessly disregarded the requirements of the Tech. Spec., as those terms have been interpreted by the NRC and the courts.

With respect to the activities conducted during the following shift, GPC believes that Mr. Kitchens made a reasonable, good faith interpretation of the Tech. Spec. under the circumstances which precludes a finding that a willful violation occurred. Mr. Kitchens conducted a careful and open review by halting the evolution, reviewing the Tech. Spec. Bases and FSAR, and consulting with a more experienced operations manager and others. He reached a reasonable conclusion that the planned evolution was analyzed and that the valves in question could be opened under administrative controls for a short period of time. Additionally, his experience at the time did not tell him that the voluntary entry into a Tech. Spec. requiring immediate action was prohibited. He knew, as a general matter, voluntary entry into Tech. Specs. was permissible and that the term "immediately" as used in the Tech. Specs. allowed some time for action. In fact, in connection with the interpretation of a another Tech. Spec. requiring immediate action, Mr. Kitchens recalled that, in 1987, the NRC had condoned delaying the initiation of immediate action until the completion of a trouble-shooting evaluation.

Mr. Kitchens was unaware of any NRC guidance which prohibited the voluntary entry into Tech. Spec. Action Statements which require immediate action; in fact, none existed. Indeed, as discussed in Section III.B.5 herein, there is considerable evidence that reasonable minds can differ as to whether voluntary entry into Tech. Spec. § 3.4.1.4.2 was permissible in October 1988. In particular, the NRC's actions with respect to this case and another recent enforcement action within Region II suggest that NRC Staff personnel can differ concerning the issue of voluntary entry into a Tech. Spec. requiring immediate action. The Company submits that this matter involves a generic industry issue which should be resolved in a forum other than an enforcement action for an event that occurred almost three years ago.

Mr. Kitchens was not motivated by any desire to reduce the outage duration or reduce outage costs; the evolution, in fact, had the opposite effect. Also, at the time, Mr. Kitchens determined that the evolution would have an insignificant effect on boron concentration. After the fact analyses have confirmed his conclusion and demonstrate that there was minimal safety significance associated with the evolution. Notably, the evolution reduced occupational exposure during the outage.

Enforcement action against Mr. Kitchens is inappropriate under these facts when NRC regulations require that, before bringing such actions, NRC find "little doubt that the individual...knew, or should have known, the required actions." At a minimum, the facts presented above raise substantial doubt that Mr. Kitchens knew or should have known that his actions violated the Tech. Spec. The Company believes Mr. Kitchens acted in good faith and that his conclusions were reasonable under the circumstances, even if the NRC now concludes they violated the Tech. Spec.

GPC has taken definitive action to ensure operators understand and follow the Tech. Specs. as intended by the NRC (See Exhibit 47). Furthermore, the Company has taken action to ensure that the institutional weaknesses in the outage planning process and in operator training and guidance which contributed to this event have been addressed.

As demonstrated in Section IV above, reasonable assurance exists that GPC currently conducts, and will in the future conduct, licensed activities in accordance with the VEGP Technical Specifications and all other NRC requirements.

Dated: August 28, 1991

3

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of

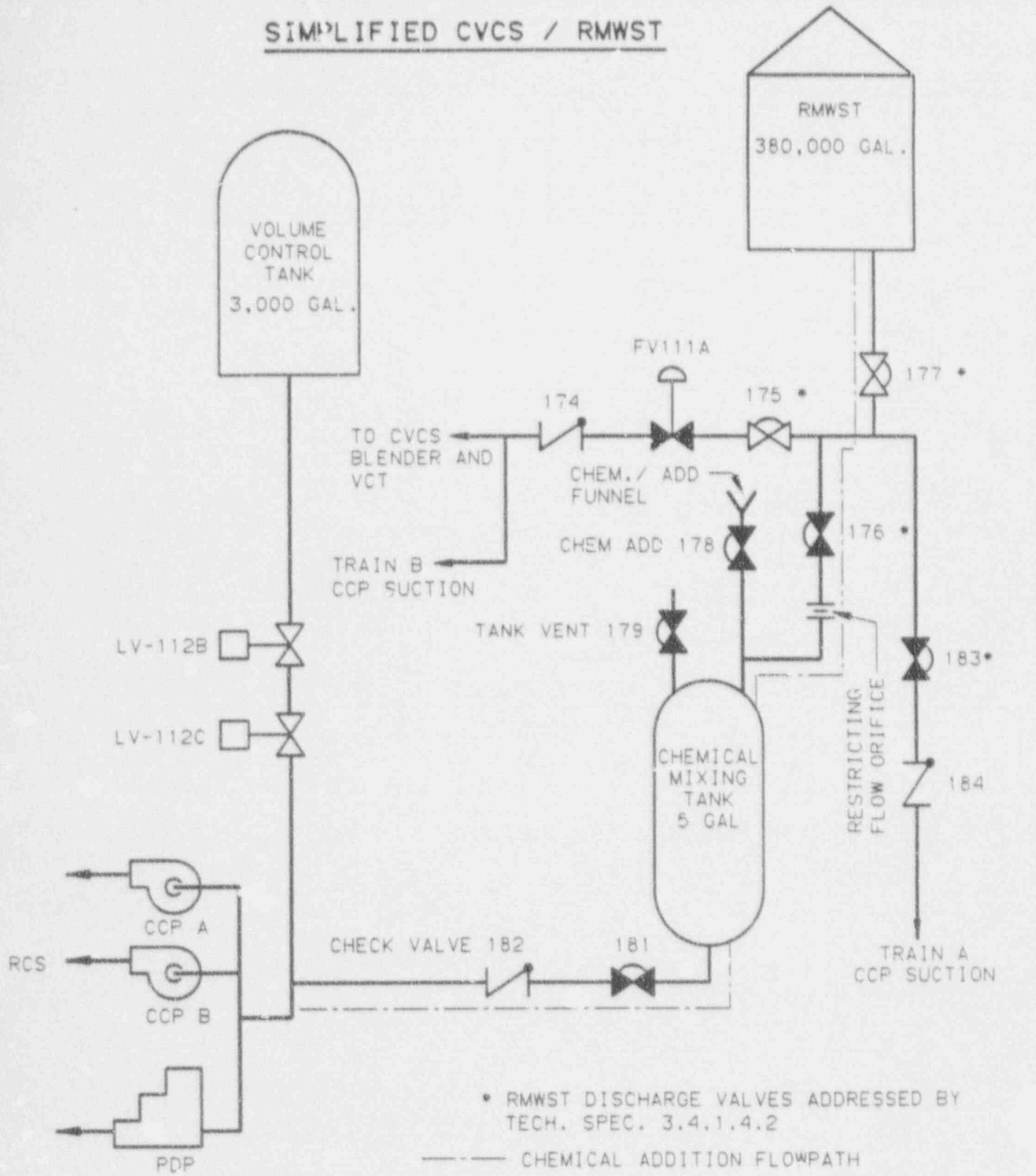
GEORGIA POWER COMPANY,	*	
et al.	*	Docket Nos. 50-424
	*	50-425
	*	
(Vogtle Electric	*	EA 91-063
Generating Plant,	*	
Units 1 and 2)	*	

GEORGIA POWER COMPANY'S RESPONSE
TO THE NRC'S JUNE 3, 1991
DEMAND FOR INFORMATION

APPENDIX I

EXHIBITS 1 THROUGH 47

SIMPLIFIED CVCS / RMWST



* RMWST DISCHARGE VALVES ADDRESSED BY TECH. SPEC. 3.4.1.4.2

—·— CHEMICAL ADDITION FLOWPATH

NOTE: ONE OF 3 PUMPS RUNNING TO ADD CHEMICALS TO RCS.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN - LOOPS NOT FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.2 Two residual heat removal (RHR) trains shall be OPERABLE* and at least one RHR train shall be in operation.** Reactor Makeup Water Storage Tank (RMWST) discharge valves (1208-U4-175, 1208-U4-176, 1208-U4-177 and 1208-U4-183) shall be closed and secured in position.

APPLICABILITY: MODE 5 with reactor coolant loops not filled.

ACTION:

a. With less than the above required RHR trains OPERABLE, immediately initiate corrective action to return the required RHR trains to OPERABLE status as soon as possible.

b. With no RHR train in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR train to operation.

c. With the Reactor Makeup Water Storage Tank (RMWST) discharge valves (1208-U4-175, 1208-U4-176, 1208-U4-177, and 1208-U4-183) not closed and secured in position, immediately close and secure in position the RMWST discharge valves.

SURVEILLANCE REQUIREMENTS

4.4.1.4.2.1 At least one RHR train shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

4.4.1.4.2.2 Valves 1208-U4-175, 1208-U4-176, 1208-U4-177, and 1208-U4-183 shall be verified closed and secured in position by mechanical stops at least once per 31 days.

---

*One RHR train may be inoperable for up to 2 hours for surveillance testing provided the other RHR train is OPERABLE and in operation.

**The RHR pump may be deenergized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with all reactor coolant loops in operation and maintain DNBR above 1.30 during all normal operations and anticipated transients. In MODES 1 and 2 with one reactor coolant loop not in operation this specification requires that the plant be in at least HOT STANDBY within 6 hours.

In MODE 3, two reactor coolant loops provide sufficient heat removal capability for removing core decay heat even in the event of a bank withdrawal accident; however, a single reactor coolant loop provides sufficient heat removal capacity if a bank withdrawal accident can be prevented, i.e., by opening the Reactor Trip System breakers.

In MODE 4, and in MODE 5 with reactor coolant loops filled, a single reactor coolant loop or RHR train provides sufficient heat removal capability for removing decay heat; but single failure considerations require that at least two trains/loops (either RHR or RCS) be OPERABLE.

In MODE 5 with reactor coolant loops not filled, a single RHR train provides sufficient heat removal capability for removing decay heat; but single failure considerations, and the unavailability of the steam generators as a heat removing component, require that at least two RHR trains be OPERABLE. The locking closed of the required valves in Mode 5 (with the loops not filled) precludes the possibility of uncontrolled boron dilution of the filled portion of the Reactor Coolant System. This action prevents flow to the RCS of unborated water by closing flowpaths from sources of unborated water. These limitations are consistent with the initial conditions assumed for the boron dilution accident in the safety analysis.

The operation of one reactor coolant pump (RCP) or one RHR pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reduction will, therefore, be within the capability of operator recognition and control.

The restrictions on starting an RCP with one or more RCS cold legs less than or equal to 350°F are provided to prevent RCS pressure transients, caused by energy additions from the Secondary Coolant System, which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by restricting starting of the RCPs to when the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures.

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT RESULTS IN A DECREASE IN THE BORON CONCENTRATION IN THE REACTOR COOLANT

15.4.6.1 Identification of Causes and Accident Description

Reactivity can be added to the core by feeding primary grade water into the reactor coolant system (RCS) via the chemical and volume control system (CVCS). Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water during normal charging to that in the RCS. The CVCS is designed to limit the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valve provides makeup to the RCS which can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a reactor makeup water pump. Normally, only one primary grade water supply pump is operating while the other is on standby.

The boric acid from the boric acid tank is blended with primary grade water at the mixing tee, and the composition is determined by the preset flowrates of boric acid and primary grade water on the control board.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flowrates deviate from preset values as a result of system malfunction.

This event is classified as an American Nuclear Society Condition II incident (an incident of moderate frequency) as defined in subsection 15.0.1.

15.4.6.2 Analysis of Effects and Consequences

15.4.6.2.1 Method of Analysis

To cover all phases of the plant operation, boron dilution during refueling, startup, cold shutdown, hot standby, and power operation are considered in this analysis.

15.4.6.2.1.1 Dilution During Refueling. An uncontrolled boron dilution accident cannot occur during refueling. This accident is prevented by administrative controls which isolate the RCS from the potential source of unborated water.

Valves 175, 176, 177, and 183 in the CVCS will be locked closed during refueling operations. These valves will block the flow paths which could allow unborated makeup water to reach the RCS. Any makeup which is required during refueling will be borated water supplied from the refueling water storage tank by the low head safety injection pumps.

15.4.6.2.1.2 Dilution During Cold Shutdown, Hot Standby, and Hot Shutdown. An analysis was performed to evaluate boron dilution events during cold shutdown, hot shutdown, and hot standby. Failure modes and effects analysis, human error analysis, and event tree analysis were used to identify credible boron dilution initiators and to evaluate the plant response to these events. For the initiators identified, time intervals from alarm to loss of shutdown margin were calculated to determine the length of time available for operator response. These calculations depended on dilution flowrates, boron concentrations, and Reactor Coolant System volumes specific to the event and mode of operation. The technique modeled realistic plant conditions and responses, including both mechanical failure and human errors.

The analysis identified four events which were considered to be the most likely initiators:

1. Demineralizer outlet isolation valve open during resin flushing.

2. Valve 226 open following BTRS demineralizer flushing operation.

3. Failure to secure chemical addition.

4. Boric acid flow control valve (FV-110A) fails closed during make-up.

Initiator 4 was found to be the most limiting event for modes 3, 4, and 5. The parameters used in the calculation of time available for operator response are listed in table 15.4.6-1. Conservative values of boron worth (pcm/ppm), as a function of RCS boron concentration, were assumed in the analysis.

Since the active volumes considered are so small in cold shutdown with the reactor coolant loops drained, it was determined that the same valves locked out in refueling would need to be locked out in cold shutdown when the reactor coolant loops are drained.

(This page has intentionally been left blank.)

17

15.4.6.2.1.3 Dilution During Full Power Operation, Including Startup.

15.4.6.2.1.3.1 Dilution During Startup. Conditions at startup require the reactor to have available at least 1.30-percent Δk/k shutdown margin. The maximum boron concentration required to meet this shutdown margin is conservatively estimated to be 1704 ppm. The following conditions are assumed for an uncontrolled boron dilution during startup: 17

A. Dilution flow is assumed to be the combined capacity of the two primary water makeup pumps (approximately 242 gal/min).

B. A minimum water volume (9757 ft^3) in the reactor coolant system is used. This volume corresponds to the active volume of the RCS minus the pressurizer volume.

15.4.6.2.1.3.2 Dilution During Power Operation. During power operation, the plant may be operated two ways, under manual operator control or under automatic T_{avg}/rod control. While the plant is in manual control, the dilution flow is assumed to be a maximum of 242 gal/min, which is the combined capacity of the two primary water makeup pumps. While in automatic control, the dilution flow is limited by the maximum letdown flow (approximately 125 gal/min). 17

Conditions at power operation require the reactor to have available at least 1.30-percent Δk/k shutdown margin. The maximum boron concentration required to meet this shutdown margin is very conservatively estimated to be 1704 ppm.

A minimum water volume (9757 ft^3) in the RCS is used. This volume corresponds to the active volume of the RCS minus the pressurizer volume.

15.4.6.2.2 Results

The calculated sequence of events is shown in table 15.4.1-1.

15.4.6.2.2.1 Dilution During Refueling. Dilution during refueling cannot occur due to administrative controls. (See paragraph 15.4.6.2.1.1).

15.4.6.2.2.2 Dilution During Cold Shutdown. For dilution during cold shutdown, the Technical Specifications provide the required shutdown margin as a function of RCS boron concentration. The specified shutdown margin ensures that the operator has 15 min from the time of the high flux at shudown alarm to the total loss of shudown margin.

15.4.6.2.2.3 Dilution During Hot Standby and Hot Shutdown. For dilution during hot standby and hot shutdown, the Technical Specifications provide the required shutdown margin as a function of RCS boron concentration. The specified shutdown margin ensures that the operator has 15 min from the time of the high flux at shutdown alarm to the total loss of shutdown margin.

15.4.6.2.2.4 Dilution During Startup. In the event of an unplanned approach to criticality or dilution during power escalation while in the startup mode, the operator is alerted to an unplanned dilution by a reactor trip at the power range neutron flux high, low setpoint. After reactor trip there is at least 19.0 min for operator action prior to loss of shutdown margin.

15.4.6.2.2.5 Dilution During Power Operation. During full-power operation with the reactor in manual control, the operator is alerted to an uncontrolled dilution by an overtemperature ΔT reactor trip. At least 19.0 min are available from the trip for operator action prior to loss of shutdown margin.

During full-power operation with the reactor in automatic control, the operator is alerted to an uncontrolled reactivity insertion by the rod insertion limit alarms. At least 36.8 min are available for operator action from the low-low rod insertion limit alarm until a loss of shutdown margin occurs.

15.4.6.3 Conclusions

The results presented above show that adequate time is available for the operator to manually terminate the source of dilution flow. Following termination of the dilution flow, the operator can initiate reboration to recover the shutdown margin. 17

1

TABLE 15.4.6-1

PARAMETERS

Dilution Flowrates:

Initiator	Flowrate (gpm)
1	63
2	120
3	3.5
4	130

Volumes:

Mode	Volume (ft^3)	Volume (gal)
3, 4	9972	74593
5a (filled)	5239	39188

Vogtle Electric Generating Plant
Unit 1 Shift Supervisor Log

Time 0000 Date 10-11-88

Time	Entry
0003	Authorized LLRT on CNMT penetration 35 - Containment Spray and 34 Containment Spray.
0018	LLRT for CNMT penetration 89 complete and Sat.
0045	Initiated draining of Hotwell to WWRB.
0300	Temporary RCS level indication installed and calibrated.
0455	JTh
0458	
0514	E
0536	RELIEVED BY J. GASSER
0536	Day Shift in J. T. Gasser
	SHIFT COMPLEMENT (UNIT #1) DATE: 10-11-88
	OSOS Hopkins; RO Tucker; FIRE TEAM
	UNIT SS Gasser; BOP Thompson; LEADER Ladd
	SUPPORT SS Ladd; ABO Eaves; Mitchell
	STA FUNCTION Gasser; OAO Mesun; Brock
	SHIFT CLERK Miles; TBO Mitchell; Atwell
	RWO Packer; SBO Cain; Packer
	Webb
	OTHERS
	Mode 5 90 = RCS Temp 65 psig = RCS Press.
0710	WTK
0721	Initiated RCS drain down.
0750	Enter LCO 1-88-599 on Met Tower ΔT indicator for failing channel check.
LE 0723	14005-1 SDM Calculation complete & Sat.
0900	Authorized channel cal on S/G Press channel 1P-515.
0906	Authorized checkout of New Fuel Elevator Bypass key to check interlocks.
LE 0820	14001-1 Shift Area Temp Log complete & Sat
0932	14000-1 Ops Shift & Daily Surveillances Complete & sat.
1253	Verified RMWST valves locked closed per 14728-1.
1257	New Fuel Elevator Bypass key returned.
1310	Authorized 24551-1 Train A CTB H_2 Monitor 1A-12979 ACOT
1549	24551-1 Train A CTB H_2 Monitor complete & Sat.
LE 1535	Initiated RCS drain to 194' elevation.
1634	JD
1658	WTB
LE 1646	RCS drain stopped at 194' elevation.

Date 10-11-88

Time	
1736	Relieved by J. Bowles JAB for JTG. RCS Level @ 194' SG Wet layup activities in progress. CR ESF HVAC tagged out. "A" DG tagged out.

SHIFT COMPLEMENT (UNIT #1) DATE 10-11-88

OSOS	J. CASH	RO	J. ACREE	FIRE TEAM	
UNIT SS	J. BOWLES	BOP	C. SALTER	LEADER	T. RYAN
SUPPORT SS	T. RYAN	ANO	B. WHITE		M. GRAHAM
STA FUNCTION	J. CASH	ORO	J. [illegible]		R. POST
SHIFT CLERK	P. JENKINS	BOO	R. POST		W. HUTCHESON
RWO	S. GARDNER	BOO	M. GRAHAM		C. KIGHT
	J. CRAGG		K. DRAWDY		
OTHERS	P. KLOPE, J. SAYGO, E. WILCOX		K. SMITH, G. WHITLEY, R. SMITH, J. KIRBY, R. REECE		

1820	Authorized performance of 24626-1 RX-2565 ACOT
1900	~~Auth~~ JAB 24931-1 LLRT for CNMT Penetration 70B Complete and Sat.
1901	CCP 'A' placed in service and CCP 'B' secured to support outage clearance of 'B' CCP.
1930	N_2 isolated from PRT, PRZR, and Rx head. PRZR and Rx head vented and aligned to Main Purge exhaust. Maintenance notified to initiate removal of PRZR manway.
LE 1920	14001-1 Shift Area Temp. Logs complete and sat.
2035	14000-1 Control Room Tech Spec round for Mode 5 complete and sat.
2200	Authorized performance of 24622-1, RE-002 ACOT and CHANNEL CAL
2202	Authorized performance of 14705-1 to prove operability of PD pump for Boric Acid Flow Path.
LE 2022	PD pump started and CCP 'A' secured to support outage clearance of 'B' CCP.
2244	24626-1, RE-2565 ACOT AND CHANNEL CAL COMPLETE AND SAT
2244	14705-1, Complete and Sat for PD pump operation
2245	Initiated venting of all SI ACCUMULATORS.

NEW DAY. CONDITIONS AS BEFORE

0017 AUTHORIZED PERFORMANCE OF I&C PROCEDURE 24937-1 TRAIN A RHR ENCAPSULATION VESSEL LLRT.

0045 24622-1, RX-002 ACOT AND CHANNEL CAL COMPLETE AND SAT.

0124 Authorized performance of 24936-1, LLRT on CNMT penetration 36.

0300 SGs in wet layup.

0400 CVCS Chemical mixing pot loaded with hydrogen peroxide. Functional clearance 1-88-371 to allow sending chemicals.

0453 ——— [illegible] ———

LE 0000 During release of DGA clearance the keep warm heater was inadvertently energized prior to filling the keep warm system. This resulted in damage to the keepwarm heater unit.

0500 ——— JWA ———

0501 ——— JTG ———

0507 ——— E ———

LE 0400 Valves 1-1208-U4-177, 1-1208-U4-176, and 1-1208-U4-181 opened to fill CVCS drain pot. Above mentioned valves immediately shut upon completion of fill in accordance with Tech Spec 3.4.6.4.a.

0533 RELIEVED BY JEFF GASSER [signature]

0533 Day Shift on [signature]

0535 ——— [signature] ———

SHIFT COMPLEMENT (UNIT #1)	DATE: 12-12-88			
OSOS	Hicks	RO	Tucker	FIRE TEAM
UNIT SS	Gasser	BOP	Thompson	LEADER Ledd
SUPPORT SS	Ladd	ABO	Eaves	Mitchell
STA FUNCTION	Ladd	OAO	Nixon	Moore
SHIFT CLERK	Blocking	TBO	Gutchell	Parker
RWO	Parker	CBO	Cain	Webb
	Harper			
OTHERS	Brack			

Mode 5

CLS at 188 °F

0650 R.E. HALE ON SHIFT FOR ON SHIFT TIME.

0705 Valves 1-1208-U4-177, 1-1208-U4-176, and 1-1208-U4-181

Date 10-12-88

TAS	Need to inject Hydrazine Peroxide into RCS.
0709	Valves 1-HHB-44-177, 178, & 181 locked closed
0743	14205-1 Plant Emergency Signals Weekly Test complete & Sat
0917	1-HV-5843 insp (CIT 13) to tighten packing per MWR 18502769.
LE 0359	RCS level at 155' 3" according to Tygon Tube. [illegible] [illegible]
LE 0524	[illegible] Shutdown Margin Calculation complete & Sat
1143	W. BRACK REPLACES S. MOORE AS F. BGDE. MEMBER
LE 0629	[illegible] Shift & Daily Surveillances complete & Sat
LE 0930	[illegible] Shift Area Temperature Logs complete & Sat
[illegible]	
1705	
1700	
1752	Relieved [illegible] [illegible]
1822	Day shift off - Night shift on

RCS [illegible] 104°F
RHR [illegible] AT 180

SHIFT COMPLEMENT (UNIT #1)		DATE 10-12-88		FIRE TEAM
OSOS	J. Williams	RO	K. Smith	
UNIT SS	Hammesley	BOP	E. Smith	LEADER Rodriguez
SUPPORT SS	Rodriguez	ABO	Mims	Reece
STA FUNCTION	Williams	OAO	Jordan	Kunitz
SHIFT CLERK	R. Smith	TBO	Grant	Saxon
AWO	Reece	CBO	Whitman	Grant
	Kunitz			

OTHERS Saxon, Nix

1845	Informed by Mark Seymore of Maintenance that snubber # 844 on SG #2 failed its IST and is inoperable. Also snubber # 845 SG #2 failed at 1535 today.
2024	Authorized 24623 charcoal cal on RX-003
2030	CR [illegible] OSP M001-1 Shift Area Temp Log complete + SAT.
2100	Exited 12006-C (complete + SAT) - Enter 12007-[illegible]
2128	14825-1 Valve Stroke Time complete + SAT for 1-HV-8843
LE 1535	Enter LCO 1-86-667 on snubber 845 on SG #2 inop
2240	OSP 14000-1 CR Tech Spec rounds complete + SAT
2400	No further entries this day

Time	Date 10-13-88
0200	New Day - Conditions As before
0219	Exit Info LCO 1-83-EUGI on 1HV-8843
0343	24623 channel Cal on RX-W3 Complete + Sat
0440	WJK
0556	JJT
0600	JTG
0616	Relieved by J Gasser [signature]
0641	wcm

SHIFT COMPLEMENT (UNIT #1)		DATE: 10-13-88			
OSOS	Hopkins	RO	Tucker	FIRE TEAM	
UNIT SS	Gasser	BOP	Tucker	LEADER	Middlebrook
SUPPORT SS	Middlebrook		Eaves		Mitchell
STA FUNCTION	Gasser	OAO	Mason		Black
SHIFT CLERK	Lane	TBO	Mitchell		Moore
RWO	Wright	CBO	Clun		Parker
	Parker				
OTHERS: Harper, Vsnaner					

Mode 5
RCS at 188'

Time	
0700	RON HALE ON SHIFT FOR ON SHIFT TIME.
0810	14005-1 SDM Calculation Complete & Sat.
0947	wmi
1030	Valves 1-1208-44-177, 176, & 181 opened to inject Hydrogen Peroxide into RCS.
1034	1-1208-44-177, 176 & 181 locked closed.
1503	R.E. HALE OFF SHIFT.
LE 1017	14000-1 Ops Shift & Daily Surveillances complete & sat
LE 1030	14001-1 Shift Area Temp Logs Complete & Sat
1651	[initials]
1652	JHA
1704	Jw
LE 1640	opened 1-1208-44-177, 176 & 181 to inject H_2 Peroxide to RCS
LE 1644	1-1208-44-177, 176, & 181 locked closed
1731	Relieved by W. Hennessy JJ Mar
1732	No Further entries this Date

JHA

Time	Date 10-13-86
1815	Night shift ON — RCS Level 182, Temp 84°F
	SHIFT COMPLEMENT (UNIT #1) DATE 10-13-86
	US: J. Williams — RO: Whitney — FIRE TEAM
	UNIT SS: Hemsing — BOP: Smith — LEADER: Redmond
	SUPPORT SS: Redmond — ASO: P. Avis — Kurtz
	FUNCTION: Hemsing — OAO: Dysing — Saxon
	CLERK: Jennings — TBO: Cannant — Reese
	Kurtz — CBO: Whitman — Cannant
	Saxon
	Reeves, Nix
1951	OSP 14001-1 Shift Area Temp Rounds complete & SAT.
2037	Authorized 24949-1 LLRT on Seal Water penetration 49
2040	OSP 14000-1 CR Tech Spec rounds complete & SAT.
2210	Started DG 1A for NSCW cooling water test - Functional Test for DCP 86-V1N-0043
2355	Authorized 24919-1 LLRT on CNMT penetration 64A & 64B (Spare Blind Flanges penetration)
2356	LLRT on Seal Return stopped (24949-1) (Pen 49)
LE 2357	DG 1A Tripped
2400	End of Day

[illegible signature]

704 REV MCS '78

Vogtle Electric Generating Plant
Unit 1 Control Log

№ 003877

Time	Tuesday Date 10-11-88
0045	Started draining hotwell to SS SWWRB
0055	PZR temp 160°F
0155	PZR temp 140°F
0221	MDAFW "B" started
0242	Aux boiler tripped due to loss of utility wtr
0254	MDAFW "B" stopped
0255	PZR temp 130°F
0340	Secured PZR aux spray PZR temp 120°F
0456	
0457	JTG
0459	JTG
0526	"A" NSCW tower return valves in normal position
0545	PT
0548	TNT
0602	C. Salter relieved by P Tucker
0602	Day Shift On: RO Perry Tucker, BOP Thad Thompson
	Plant Status: Mode 5 100°, 70 psig, RHR A & B, CCP B running, SRNI 40 cps, 0618 00S, RCP 00S
0606	WMT #10 → River started
0615	2 utility water pumps placed in aux to maintain higher system pressure to prevent tripping of Aux. boiler
0635	Momentarily placed BA xfer pump #1 to auto position to verify SSMP for changing clears Alarm cleared as required.
0715	WMT #10 → River complete
0721	Began RCS drain.
0723	OSP-14005-1 complete (gpm 3.4% alk)
0820	OSP-14001-1 complete for day shift
0815	MFPT's A & B taken off the turning gear
0822	MFPT A lube oil system shutdown
0824	MFPT B lube oil system shutdown.
0839	ICS-462 @ 48% Plan to maintain this level at present time
0914	Service air established to containment. 1-HV-9385A & B open
0932	OSP-14000-1 complete for Day shift
0938	WMT #9 → River started
1000	RHR pump "A" stopped
1026	Started slow level decrease of RCS to ≈ 25% per level
1048	WMT #9 → river complete
1207	Stopped ctmt coolers 1, 2, 7, 8, stopped CRDM cooling fans
1228	RCS cold cut @ 25%

Georgia Power Company
Vogtle Electric Generating Plant
Unit 1 Control Log

wm

№ 0038.8

Date 10-11-98

Time	
1257	Accum #4 N2 → cont atmosphere per 13105-1
1328	Stopped cont pre-access filter unit 1 per SOP-13125-1
1345	Started Air compressor #2
1415	A/C #2 stopped
1422	A/C #2 restarted (High air supply demand)
1430	RCS Tygon tube valved in per 13005-1
1500	Placed DG1B FOST on recirc per SOP 13146-1 at chemistry request by starting
	FO xfer pump #4
1505	RCS draining to 194' elevation commenced via RHR letdown -ALVLS
1540	Accumulator #4 drain ~~in progress~~ commenced 1st ...
1612	Accum venting completed
1636	——— JB ———
1646	RCS level @ 194' elevation maintaining
1651	——— WR ———
1659	WMT #10 → Savannah River started
1700	——— [illegible] ———
1744	——— JA ———
1752	——— CDS ———
1805	Relieved by John Aren [illegible]
1805	NIGHT SHIFT ON: RO J ACREE
	BOP C SALTER
	PLANT STATUS: MODE 5, 108°F RCS TAVG @ 38 PSI
	RCS @ 194' [illegible]
	COOLING AND LETDOWN), CCP 'B' IN SERVICE.
1806	WMT #10 TO RIVER COMPLETE.
1818	SHUT PRT N2 SUPPLY VALVES (1HV-8047 + 1HV8033) AND
	Rx VESSEL HEAD VENT TO PRT VALVES (1HV-442A + 1HV-442
	PER SOP 13005-1.
1905	STARTED CCP 'A'.
1906	SECURED CCP 'B' / INIT S/G TUBE BUNDLE DRAINING.
2022	PDP STARTED TO ACCOMODATE CCP 'B' TAG OUT.
2024	SECURED CCP 'A'.
2034	OSP 14000-1 COMP + SAT.
2115	WMT #9 TO RIVER STARTED.
2205	BORIC ACID XFER PUMP #6 PLACED IN AUTO; BSMP
	LIGHT VERIFIED ON ("CHARG SYS BYP")
2221	WMT #9 TO RIVER COMPLETE.
2214	BORIC ACID XFER PUMP #6 STARTED.
2226	BORIC ACID XFER PUMP #6 SECURED.

Vogtle Electric Generating Plant
Unit 1 Control Log

N° 003879

Date 10-11-88

Time	
2227	BORIC ACID XFER PUMP #7 STARTED.
2232	BORIC ACID XFER PUMP #7 SECURED.
2244	OSP 14705-1 "BORON INJECTION FLOW RATE VERIF" Comp + SAT.
2245	STARTED SI ACCUM VENTING
2359	LAST ENTRY THIS DAY.

Time	Date 10-12-98
0000	NEW DAY.
0150	COMMENCING RCS DRAIN TO 188' ELV / S/G
	TUBE BUNDLE DRAIN COMPLETE.
0300	S/G'S PLACED IN WET LAYUP.
LE 0030	ALL S.I. ACCUMULATORS COMPLETELY DEPRESSURI
0333	RCS LEVEL @ 189'10"
0425	RCS LEVEL @ 189'.
0455	—— ε ——
0456	—— JDA ——
0458	JTG
0501	RCS LEVEL @ 188'9".
0538	—— TNT ——
0550	—— PT ——→
0558	RELIEVED BY P. TUCKER, J. [illegible]
0558	Day Shift On: RO - Perry Tucker, BOP - Thad Thompson
	Plant Status: Mode 5 - 40 gpm, RHR 'B' [illegible] & [illegible] → CVCS
	RCS Drain to 188'3" in progress (RHR letdown → CVCS → RHUT)
	DG 1A OOS, CCP 'B' OOS, CCP 'A' in PTL ready for boration flow
	if needed, Core exit T/C 10[illegible] °F
0638	RCS level @ 188'7", wide range 58%
0700	WMT #10 → Savannah River started
0741	RCS level @ 188'4", wide range @ 53%
0743	OSP-14205-1 complete & sat
0754	RCS level @ 188'3"
0810	WMT #10 → River completed.
0824	OSP-14005-1 complete (SDM @ 3.6% ΔK/K)
0829	OSP-14000-1 complete for day shift
1007	@ 0900 RWST 2528 ppm and SFP 2648 ppm
1102	WMT #9 → River initiated.
1158	WMT #9 → River complete
1329	DG 1B FOST recirc stopped, both FO xfer pumps in auto.
1500	CVCS mixed bed demins swapped 1-1208-D1-003 now in service (→ [illegible]
1549	Demins for CVCS bypassed; 112A back to VCT
1556	—— [illegible]
1702	—— [illegible]
1709	—— [illegible]
1724	—— AMG
1756	—— [illegible]
1837	Relieved by Keith Smith Perry Tucker

704 NEA NCB 128

Time | Date 10-12-98

Time	
	Night Shift on, RO's A. Keith Smith, BOP's Phillip Smith. Extra RO's Gary Whitley.
	Commenced release of WMT #10 → River.
	WMT #10 → River complete
2001	CVCS Mixed Bed Demin #3 valved out and CVCS Mixed Bed Demin #2 valved in per Don Goodwin
2030	RCS draining to 188' 0" complete, exited SOP 13005.
2100	Exited UOP 12006-C (complete), entered UOP 12007-C.
2118	Placed CVCS Mixed Bed Demin #2 in service
2133	Seal injection isolated for RCP's 2 + 3 for outage work
2230	Maintaining RCS level at 188' 0", per UOP 12007-C discontinuing continuous Tygon tube watch and commencing four hour checks.
2323	Commenced release of WMT #9 → river.
2354	End of day, last Entry.

704763A MCS128

№ 003882

Date 10-17-88

0000	New Day.
0053	WMT #9 discharge complete.
LE 0011	Local Tygon tube level check complete
0216	Main Turb. L.O. reservoir has been drained.
0355	Chemistry reports RCS CB sample taken at
	0015 CST was 1130 ppm.
0450	Local Tygon tube level check complete.
0507	Opened PCB 161860 per switch house.
0546	—— $\boxed{TNT}$ ——→
0555	——→ JTG ———
0556	JFH
0605	Night Shift off. Relieved by Thad Thompson.
0605	Day Shift On. Thad N Thompson is the Unit 1 Rx Operator
	P Tucker is the Unit 1 Balance of Plant Operator
	J. Gasser is the Unit 1 Shift Supervisor
	Plant Status - Mode 5, 25 gpm, RCS level - 188'0", DG1A [illegible] RCS temp 1(
	RHR Train B providing shutdown cooling & letdown → CVCS
0628	— P ——→
0639	—— LPV ——→
0800	RCS tygon tube level checked locally ~~at~~ and main reads 188'0" Indication on
	RCS WR & NR temporary level indications also read 188'0"
0810	OSP-14005-1 (Shutdown Margin Calculation) complete & satisfactory. SDM: 8.
0958	Maximized RHR (RCS) letdown through CVCS demins to enhance RCS clean
1017	WMT #10 ——→ River initiated OSP-14006-1 complete & satisfactory findings
1050	RCS tygon ~~tube level checked locally and reads 188'0" indication~~ on
	RCS WR & NR temporary level indications also read 188'0"
LE 1030	Hydrogen peroxide addition initiated, OSP-14001-1 for Area Temps complete & sat
LE 1034	Hydrogen peroxide addition completed.
1147	WMT #10 ——→ River completed.
1238	All core exit thermocouples have been disconnected except for L8 (TS019) and
	N6 (TS022) 2 Incore CET's required with head on per UOP-12067-C
1450	RCS tygon tube ~~tu~~ level checked locally & verified to read same as WR & N
	temporary indications on QMCB
1624	WMT #9 ——→ River started.
1648	——— TJM ———
1650	——— WJH ———→
1700	——— J.J ———
1727	WMT #9 ——→ River complete.
1743	——— JGW ———

704783A MC3179

Nº 00388

Time | Date 10·13·88

Time	
1745	——— RL ———
1820	Day Shift off - G. Whitley relieving Thos? Thompson
1820	Night shift on: - G.L Whitley - R.O, A.R Smith - BOP
	Plant status: Mode 5, Rx vessel lvl at 188'0"
	Train B RHR in service, RHR Letdown in service
	Train A D/G OOS Circ water OOS, waterboxes drained
1850	RCS Tygon Tube ~~187'~~ 188' - Control Rm indication 188'0
1956	OSP 14000-1 Complete : Sat
2016	Stopped Air Comp #2. Temporary Air Comp in operation
2100	Started Air Comp #2. utility water providing cooling
2117	Secured #1 Air Comp. for cooling water swap over
2130	Air Comp #2 Tripped, Started #1 air comp (comp using utility water for cooling)
2137	Air Comp #2 Tripped at 2130 on Low cooling water pressure while the PEO was adjusting.
2150	Tygon Tube lvl 188' - Cont Rm indications - 188'
2156	#2 Air Comp tripped ~~on~~ after start, #3 air comp started
2204	#2 Air Comp started
2206	#3 Air Comp secured
2210	D/G A started
2307	Core Exit Thermocouples L8 & N6 disconnected in preparation for Rx vessel head removal
2320	D/G A Tied to Grid
2321	D/G A taken off Grid due to excessive VAR Loading (Sim
2337	D/G A Tripped
2400	End of Day

UNIT NO. ONE DATE 10 / 8 / 88

UNIT COOLDOWN TO COLD SHUTDOWN

MANUAL SET
NO. 12

1.0 PURPOSE

This procedure provides instructions for maintaining hot standby following reactor trip, maintaining hot standby following reactor shutdown, taking the unit from hot standby to cold shutdown. Instructions are provided for maintaining conditions stable at points between.

2.0 PRECAUTIONS AND LIMITATIONS

2.1 PRECAUTIONS

2.1.1 If this procedure is terminated prior to completion, the Unit Shift Supervisor (USS) should note the reason for the termination in the comments section.

2.1.2 The Reactor Coolant System (RCS) pressure and temperature shall be maintained within the operating region of Figure 1.

2.1.3 Do not add positive reactivity by more than one controlled method at a time while the reactor is subcritical.

2.1.4 Whenever RCS temperature is above 160°F, at least one RCP should be in operation. Preferably Pump 4 to ensure best spray capability.

2.1.5 The hydrogen concentration in the RCS must be reduced to less than 5cc/kg prior to opening any RCS component.

2.1.6 The boron co[illegible]ration [illegible] the pressurizer should not be different [illegible]m the RCS [illegible]y more than 50 ppm. Pressurize[illegible] [illegible]ackup Heaters may be energized as necessary t[illegible] [illegible]qualize the boron concentration.

2.1.7 The Control Rod Drive Mechanism (CRDM) Cooling System shall be operating when RCS temperature is greater than or equal to 350°F or when any CRDM is energized.

8810070235

2.1.8 During cooldown, all Main Steam Isolation Valves (MSIVs) should be open or atmospheric reliefs balanced to allow uniform cooldown of all Reactor Coolant System (RCS) loops and Steam Generators (SGs). Steam dump is the preferred method of heat removal.

2.1.9 The Residual Heat Removal (RHR) Pump Suction Line should not be isolated from the RCS unless there is a steam bubble in Pressurizer.

2.1.10 One Reactor Coolant Pump (RCP) should be running anytime RCS temperature is changed by more than 10°F in one hour.

2.1.11 Spray flow into the Pressurizer should not be initiated if the temperature difference between the Pressurizer steam space and the spray fluid exceeds 125°F.

2.1.12 Before auxiliary spray is initiated with a temperature difference between the pressurizer steam space and the spray fluid exceeding 320°F, notify the USS. (Technical Specification 5.7.1)

2.1.13 While in Hot Standby, feeding Steam Generators should be continuous to minimize thermal stresses on the Feedwater Nozzle.

2.1.14 Vacuum should be maintained on the Main Turbine following unit shutdown until the Turbine coasts down to approximately 66% rated speed (1200 rpm) unless an emergency dictates rapid coastdown of the Turbine Rotor.

2.1.15 The Main Turbine should be kept on Turning Gear until metal casing temperatures have returned to ambient. Bearing lube oil circulation must also be maintained.

2.1.16 During periods of operation with the RCS level below the Reactor Vessel Flange elevation (194 feet elevation), ongoing work activities should be closely scrutinized and any work activity limited that has the potential for reducing RCS inventory.

2.2 LIMITATIONS

2.2.1 The RCS pressure and temperature shall not exceed 425 psig and 350°F when open to the RHR system.

2.2.2 While in Modes 3 and 4, shutdown margin shall be greater than or equal to the limit specified in Technical Specification 3.1.1.2, Figure 3.1-1.

2.2.3 While in Mode 5, shutdown margin shall be greater than or equal to the limit specified in Technical Specification 3.1.1.2, Figure 3.1-2.

2.2.4 While in Mode 3, at least two RCS loops shall be in operation with the Reactor Trip Breakers closed and at least one in operation with the Reactor Trip Breakers open. (Technical Specifications 3.4.1.2)

2.2.5 While in Mode 4, at least two RCS loops and/or RHR trains shall be operable and at least one of the RCS loops and/or RHR trains shall be in operation. (Technical Specifications 3.4.1.3)

2.2.6 While in Mode 5 with the RCS loops filled, at least one RHR train shall be operable and in operation and either one additional RHR train operable or the secondary side water level of at least two steam generators shall be greater than 17% wide range. (Technical Specification 3.4.1.4.1)

2.2.7 While in Mode 5 with the RCS loops not filled, at least two RHR trains shall be operable and at least one RHR train shall be in operation. (Technical Specification 3.4.1.4.2)

2.2.8 While in Modes 4, 5, and 6 with the Reactor Vessel Head on, at least one of the following cold overpressure protection systems shall be operable:

a. Two PORVs with lift settings which do not exceed the limits established in Figure 1,

b. Two RHR suction Relief Valves each with a setpoint of 450 psig ±3%, or

c. The RCS depressurized with an RCS vent capable of relieving at least 670 gpm water flow at 470 psig. (Technical Specification 3.4.9.3)

2.2.9 While in Modes 5 and 6, at least one Charging Pump in the required boron injection flow path shall be operable. (Technical Specification 3.1.2.3)

2.2.10 The primary to secondary pressure differential shall not exceed 1600 psid or a secondary to primary pressure differential of 670 psid during unit operations or leak tests.

2.2.11 The maximum cooldown of the RCS shall be limited to 100°F in any one hour period. (Technical Specification 3.4.9.1)

2.2.12 The maximum cooldown of the pressurizer shall be limited to 200°F in any one hour period. (Technical Specification 3.4.9.2)

2.2.13 The maximum temperature differential between auxiliary spray water and pressurizer steam space is 625°F. (Technical Specification 3.4.9.2)

2.2.14 The temperature of both the primary and secondary coolant in the Steam Generators shall be greater than 70°F when the pressure of either coolant in the Steam Generator is greater than 200 psig. (Technical Specification 3.7.2)

2.2.15 While in Modes 3, 4 and 5, both channels of Source Range Nuclear Instrumentation shall be operable. (Technical Specifications Table 3.3-1, 6.B)

2.2.16 While in Modes 3, 4, and 5 at least one channel Source Range Nuclear Instrumentation should be selected to Recorder NR-45 and the CONTROL ROOM HI FLUX LEVEL AT SHUTDOWN alarm operable.

2.2.17 While in Modes 5 and 6, with the RCS level below Reactor Vessel Flange elevation (194 feet elevation), the RWST will be operable with a minimum volume of 70,832 gallons (5% of instrument span) of water at a boron concentration between 2000 and 2200 ppm.

3.0 <u>INITIAL CONDITIONS</u>

3.1 The reactor is shut down either following normal shutdown or reactor trip with Shutdown Rods either withdrawn or inserted.

3.2 RCS temperature is stabilized at no load Tavg under control of the steam dumps in Steam Pressure mode or by operation of the Steam Generator Atmospheric Relief Valves.

3.3 RCS pressure is stable at normal operating pressure.

3.4 At least one RCP is operating.

3.5 Pressurizer level is at approximately or returning to the program level with either the Positive Displacement (PD) Pump or a Centrifugal Charging Pump (CCP) operating to supply normal charging and RCP seal injection flow.

3.6 SG levels are at 45% to 55% NR level with Auxiliary Feedwater (AFW) operating.

3.7 The main Turbine is tripped and either coasting down or on the Turning Gear.

4.0 INSTRUCTIONS

NOTES

a. This procedure is divided into sections which permit either cooldown or maintaining stable conditions within a specified mode. Section E may be performed concurrently with Sections A,B,C,D.

b. Aster'sk (*) steps beside INITIAL steps indicates steps that generate additional documents.

c. This procedure is written using Train A designations. Train B component designations are shown in parenthesis.

The sections of this procedure are:

A. Hot Standby Following Reactor Shutdown or Trip.

B. Cooldown to not less than 350°F.

C. Cooldown to not less than 205°F.

D. Cooldown to Cold Shutdown (less than 200°F).

E. Secondary Plant Shutdown.

SECTION A: Hot Standby Following Reactor Shutdown or Trip

A4.1 OPERATING IN HOT STANDBY FOLLOWING REACTOR SHUTDOWN OR TRIP:

		INITIALS
A4.1.1	If this procedure has been entered from a reactor trip, then perform the following:	
	a. INITIATE 10006-C, "Reactor Trip Review",	[illegible] *
	b. If entering this procedure from SI termination, then perform 11886, "Recovery From ESF Actuation",	N/A
	c. If required, INITIATE STARTUP of the Auxiliary Boiler per 13760-C, "Auxiliary Steam Boiler System",	[illegible]
	NOTIFY Chemistry Department,	
	d. If applicable, ENSURE that TDAFW Pump has been stopped per 13610, "Auxiliary Feedwater System" and returned to STANDBY per 13610, Checklist 2,	[illegible] *
	e. When Source Range channels indication stabilize PLACE CONTROL ROOM HI FLUX LEVEL AT SHUTDOWN alarm in operation by performing the following:	
	(1) NOTIFY I&C and RESET the HI FLUX AT SHUTDOWN alarm setpoint per 24695 and 24696, "N.I. System Source Range Channel Calibration",	LPV
	(2) ENABLE THE HI FLUX AT SHUTDOWN alarm by placing the HIGH FLUX AT SHUTDOWN NORMAL/BLOCK switches to the NORMAL,	LPV

INITIALS

(3) VERIFY annunciator SOURCE RNG HI SHUTDOWN FLUX ALARM BLOCKED ALB-10 B01 resets. LPV

(4) SELECT both channels of Source Range indication on Recorder NR-45. NWS

ANNOTATE chart to reflect channels selected.

f. CALCULATE SHUTDOWN MARGIN per 14005, "Shutdown Margin Calculations". NWS *

g. If necessary, BORATE the RCS per 13009, "CVCS Reactor Makeup Control System". NWS

h. SHUT DOWN the CVCS BTRS System by performing the following:

(1) PLACE the CVCS BTRS SELECTOR Switch HS-10351 in the OFF position. NWS

(2) CLOSE the BTRS Demineralizer Flow Control HV-0387 to the FULLY CLOSED position. NWS

i. DIRECT Chemistry to sample the RCS hydrogen, gas activity concentrations and PERFORM an RCS Iodine sample analysis per the required frequencies of Technical Specifications Table 4.4-4. NWS

Person Contacted Pam Crowell Date 10-8-88 Time 2400

j. MAXIMIZE CVCS letdown purification flow rate per 13006, "Chemical And Volume Control System Startup And Normal Operation". NA

10/10/88 1928
Date Time

* [illegible] 73 gpm per [illegible]

INITIALS

k. MONITOR Main Turbine coastdown,

(1) ENSURE that the Turning Gear Motor Control Handswitch is in AUTO/PULL-TO-LOCK position, ____

(2) When Turbine Rotor reaches zero speed, VERIFY all Lift Pumps, Turning Gear Oil Pumps ON and Turning Gear engagement. ____

l. STOP both Heater Drain Pumps, ____

m. STOP all but one Condensate Pump, ____

n. REDUCE in-service Condensate Demineralizer Powdex Vessels as applicable per 13616, "Condensate Filter Demineralizer System",

o. PLACE the Condensate and Feedwater System on Long cycle recirc per 13615, "Condensate And Feedwater Systems", ____

p. NOTIFY Chemistry to initiate placing condensate and feedwater into proper chemical wet layup, ____

q. If necessary, SHUT DOWN all but one Circulating Water Pump, ____

r. If necessary, SHUT DOWN all but one River Makeup Pump and RECORD time in the Unit Control Log Book, ____

s. ENSURE SG Blowdown Isolation Valves 1-HV-7603A(B, C, D) open. ____

A4.1.2 If No-Load Tavg cannot be maintained due to excessive steam demand, REDUCE steam demand by performing the following:

a. ENSURE MSR Heating Steam Supply Valves HS-6015 and HS-6030 closed, ____

b. TRANSFER the Auxiliary Steam System steam supply to the Auxiliary Boiler per 13761, "Auxiliary Steam System". ____

INITIALS

c. TRANSFER the Turbine Steam Seal supply to the Auxiliary Steam Supply per 13825, "Turbine Steam Seal System".

d. TRANSFER the SJAE steam supply to the Auxiliary Steam Supply per 13620, "Condenser Air Ejection System". LPV

e. If Main Generator is to be shut down for more than two days, then to prevent overheating relay 360A, OPEN links TBR 28, 29 and 30, located in Protective Relay Panel Bay 4, per 00306-C, "Temporary Jumper And Lifted Wire Control".

f. If the Generator Regulator Panel (1328-P5-GRC) is to be de-energized for maintenance, then OPEN links TBR 56 and 57 and TBS 4 and 5 located in Protective Relay Panel Bay 4, per 00306-C, "Temporary Jumper and Lifted Wire Control". This will prevent tripping Lockout Relays 386 G9 and 386 G10 which trip Generator Output Breakers.

g. At the Main Transformer Control Cabinets, de-energize the Transformer Oil Pumps and Fans per 13800, "Main Turbine Operation" Sub-subsection 4.3.1.

A4.1.3 Either OPERATE unit systems as necessary to maintain the unit at Hot Standby, or PROCEED to either Section B to initiate unit cooldown or 12003-C, "Reactor Startup" to return to power.

END OF SECTION A

Note [illegible] approved [illegible] approved procedure [illegible] Jumper [illegible] suggestion sheet submitted

SECTION B: Cooldown to not less than 350° F

NOTE

This section directs cooldown to 375°F or any point between without crossing the boundary for Mode 4 at 350°F.

B4.1 PREPARATION FOR UNIT COOLDOWN

		INITIALS
B4.1.1	If required to cooldown secondary systems, then INITIATE Section E of this procedure.	
B4.1.2	If Condenser vacuum is being maintained, then INITIATE placing a steam blanket on the MSR's per 13800, "Main Turbine Operation".	NA
B4.1.3	INITIATE pressurizer and RCS boron equalization by energizing Pressurizer Backup Heaters.	JRA
B4.1.4	MAXIMIZE CVCS letdown purification flowrate. NA date/time	NA
B4.1.5	INITIATE Borating the RCS to the cold shutdown boron concentration per 13009, "CVCS Reactor Makeup Control System".	JRA
	If applicable, PERFORM 14835, "Boric Acid Injection Check Valve Cold Shutdown Inservice Test" during the boration.	JRA *
B4.1.6	DIRECT Chemistry to sample the RCS and Pressurizer boron concentration.	JRA
B4.1.7	If withdrawn, INSERT all Shutdown Banks to the fully inserted position.	NA
B4.1.8	OPEN the Reactor Trip breakers.	JRA

INITIALS

B4.1.9 If not currently in progress, INITIATE RCS gaseous activity degas by performing the following:

a. ENSURE that the Pressurizer Steam Space Sample line is in operation by verifying that the PRZR STM SAMPLE IRC/ORC Valves HV-3513/HV-3514 are open. **NA

b. NOTIFY Chemistry to adjust the pressurizer steam space sample flow rate to maximum. **NA

c. While maintaining hydrogen cover gas, DEGAS the RCS by raising VCT gas purge flow rate to the Gaseous Waste Processing System to approximately 1.2 scfm using HIC-1094, as limited by the Hydrogen Recombiners. **NA

B4.1.10 When notified by Chemistry that the RCS gaseous activity has been reduced to an acceptable level, TRANSFER VCT cover gas to Nitrogen and INITIATE RCS Hydrogen degas per 13007, "VCT Gas Control And RCS Chemical Addition". **NA

NOTE

Prior to opening the RCS to containment the hydrogen concentration shall be less than 5 cc/kg.

B4.1.11 START both Containment Pre-access Filter Units using CTB PREACCESS FLTR UNIT-1/2 FAN HS-2620/2621. Unit #2 tagged and #1 in service JM
date/time

B4.1.12 If it is planned to cool down to Cold Shutdown, and if not performed in the previous three months, COMPLETE 14748, "AFW Check Valve Shutdown Inservice Test". JM*

** RCS H_2 < 5 cc/KG per M.W.

INITIALS

B4.2 RCS COOLDOWN TO 375°F

B4.2.1 COMMENCE RCS/Pressurizer pressure and temperature trending at 30 minute intervals using Data Sheet 1 and ERF computer. (Technical Specification 4.4.9.1)

Data taking and plotting may be suspended during holds in the cooldown if the duration is expected to exceed one hour.

NOTE

It is recommended that the RCS temperature be maintained between 75° F and 125° F less than pressurizer temperature. (See Figure 1.)

B4.2.2 COMMENCE the cooldown to 375°F and 540 psig at a recommended rate of approximately 50°F per hour by performing the following:

a. REDUCE the number of operating RCPs to two per 13003, "Reactor Coolant Pump Operation". JA

Pumps 4 and 1 are the preferred running pumps.

b. INITIATE Pressurizer cooldown and depressurization by slowly opening the Pressurizer Spray Valves. JA

If necessary, selectively DE-ENERGIZE Pressurizer Back-up Heaters by placing Control Switches to PULL-TO-LOCK.

CAUTION

RCS temperature and pressure shall be maintained within the acceptable operating region of Figure 1.

c. Slowly ADJUST the Steam Dump Controller setpoint or if applicable the Atmospheric Relief Valves to initiate RCS cooldown. JA

INITIALS

B4.2.3 At approximately 2185 psig, OBSERVE PRZR PORV BLOCK VALVES HV-8000A and HV-8000B auto close.

NOTE

Depending on the rate of RCS cooldown and depressurization, Step B4.2.5 may occur before Step B4.2.4.

B4.2.4 At approximately 550°F RCS temperature PERFORM the following:

a. VERIFY status light LO LO TAVG TRAIN A STEAM DUMP INTL P12 illuminated,

b. BYPASS the LO LO TAVG interlock by momentarily placing the Train A and B Steam Dump Interlock Selector Switches to the BYPASS INTERLOCK position,

If operating on Steam Dumps, then VERIFY Steam Dump Cooldown Valves PV-0507A, B and C are open by observing ZLB-2 on QMCB,

CAUTION

If the RCS is allowed to pressurize above P11 and SG pressure is below 585 psig, Safety Injection and Steam Line Isolation will occur.

B4.2.5 At approximately 1970 psig, manually BLOCK Pressurizer Pressure and Steam Line Pressure Safety Injection and Steam Line Pressure Steam Line Isolation signals by performing the following:

a. It is is planned to cool down for refueling, then PERFORM 14710, "Remote Shutdown Panel Transfer Switch And Control Circuit 18 Month Surveillance Test" Data Sheets 3A and 3B in lieu of the following substeps,

b. VERIFY Block Permissive Status Light PRZR LO PRESS SI BLOCK PERM P11 illuminates,

INITIALS

c. BLOCK the Low Pressurizer Pressure Safety Injection signal using PRZR PRESS SI BLOCK/RESET A and B handswitches HS-40012 and 40013. JA

d. OBSERVE Status Lights PRZR TRAIN A/B SI BLOCKED illuminated. JA

e. BLOCK the Low Steam Line Pressure Safety Injection signal using LOW STM PRESS SI/SLI BLOCK RESET handswitches HS-40068 and 40069. JA

f. OBSERVE Status Lights STMLINE ISO TRAIN A/B SI BLOCKED illuminated. JA

B4.2.6 CHECK that Pressurizer level is between 20% and 40%. JA

B4.2.7 As RCS pressure lowers, OPEN additional Letdown Orifice Isolation Valves and ADJUST PIC-131 setpoint to maintain desired letdown flowrate.

B4.2.8 During RCS depressurization, MAINTAIN all RCP seal injection flow rates between 8 and 13 gpm by adjusting the Charging Header Flow Controller HC-0182.

B4.2.9 At approximately 950 psig, ISOLATE ECCS Accumulators by performing the following:

a. REMOVE TAG, UNLOCK and CLOSE the Accumulator Discharge Isolation Valve 480V MCC Breakers:

	UNIT 1	UNIT 2
ACCUM-1	1ABE-19	2ABE-19
ACCUM-2	1BBC-19	2BBC-19
ACCUM-3	1ABC-19	2ABC-19
ACCUM-4	1BBE-19	2BBE-19

INITIALS

b. CLOSE the Accumulator Isolation Valves,

ACCUM-1 HV-8808A, LPV

ACCUM-2 HV-8808B, LPV

ACCUM-3 HV-8808C, LPV

ACCUM-4 HV-8808D. LPV

c. VERIFY annunciators ACCUM TANK 1(2,3,4) ISO VLV 8808A(B,C,D) NOT FULLY OPEN in alarm. ALB06-A05,B05,C05,D05. JA

d. OPEN, LOCK and TAG the Accumulator Discharge Isolation Valves 480V MCC Breakers,

	UNIT 1	UNIT 2	
ACCUM-1	1ABE-19	2ABE-19	
ACCUM-2	1BBC-19	2BBC-19	
ACCUM-3	1ABC-19	2ABC-19	
ACCUM-4	1BBE-19	2BBE-19	

B4.2.10 When steam pressure falls too less than 550 psig, at the USS's discretion the Steam Generators may be supplied by the running Condensate Pump per Section E4.2 of this procedure.

INITIALS

B4.2.11 Either OPERATE unit systems as necessary to maintain RCS within the following parameter values or PROCEED to either Section C to continue the cooldown or 12002-C, "Unit Heatup to Normal Operating Temperature and Pressure" to commence a heatup.

RCS temperature	375°F ±10°F
RCS pressure	540 psig ±25 psig
Pressurizer level	at program level

END OF SECTION B

SECTION C: Cooldown to not less than 205°F

NOTE

This section directs cooldown to 225°F or any point between without crossing the boundary for Mode 5.

C4.1 PREPARATION FOR CONTINUING UNIT COOLDOWN.

INITIALS

C4.1.1 If required to cooldown secondary systems and break condenser vacuum, then INITIATE SECTION E of this procedure.

CAUTION

Maintain pressurizer cold calibration level greater than 17%.

C4.1.2 If it is planned to cool down to cold shutdown, then ALLOW pressurizer level to rise during the cooldown to not greater than 80% cold calibrate.

C4.1.3 COMMENCE RCS/Pressurizer pressure and temperature trending at 30 minutes intervals using Data Sheet 1 and ERF computer. (Technical Specification 4.4.9.1)

Plotting may be suspended during holds in the cooldown if the duration is expected to exceed one hour.

INITIALS

C4.2 RCS COOLDOWN TO 225°F.

NOTE

It is recommended that the RCS temperature be maintained between 75°F and 125°F less than pressurizer temperature. (See Figure 1.)

C4.2.1 COMMENCE the cooldown to 225°F and 250 psig at a recommended rate of approximately 50°F per hour by performing the following:

a. CONTINUE the pressurizer cooldown and depressurization by slowly opening the Pressurizer Spray Valves, LPV

If necessary, selectively DE-ENERGIZE Pressurizer Backup Heaters by placing Control Switches to PULL-TO-LOCK,

CAUTION

RCS temperature and pressure shall be maintained within the acceptable operating region of Figure 1.

b. Slowly ADJUST the Steam Dump Controller setpoint or if applicable the Atmospheric Relief Valves to initiate RCS cooldown. LPV

C4.2.2 If it is planned to cool down for refueling, then prior to reaching 350°F, REQUEST confirmation from Engineering/Maintenance that actions have been taken to preclude Reactor Vessel Seismic Tie Rod Binding. DCA

C4.2.3 Prior to reaching 350°F, NOTIFY Chemistry to isolate PERMS CVCS Letdown Monitor RE-48000. LEV

INITIALS

C4.2.4 Prior to reaching 350°F, PLACE the Cold Overpressure Protection System (COPS) in operation by performing the following:

a. If not performed in the previous three months, PERFORM 14860, "PORV Cold Shutdown Inservice Test", [illegible] *

b. ARM the A and B COPS by placing the PRZR PORV BLOCK VLV COLD OVERPRESSURE CNTL handswitches HS-8000G and 8000H to the ARM position, LPV

c. VERIFY the following annunciators alarmed upon arming COMS:

A COLD OP ACTU VLV HV-8000A NOT FULL OPEN (ALB12 E06), LPV

B COLD OP ACTU VLV HV-8000B NOT FULL OPEN (ALB12 F06), LPV

d. ENSURE PRZR PORVs PV-455A and 1-PV-456A are closed and the handswitches in AUTO, LPV

e. ENSURE OPEN PRZR PORV BLOCK Valves HV-8000A and 8000B, LPV

NOTE

Step f satisfies Technical Specification surveillance 4.4.9.3.1.c

f. VERIFY the following annunciators reset:

A COLD OP ACTU VLV HV-8000A NOT FULL OPEN (ALB12 E06), LPV

B COLD OP ACTU VLV HV-8000B NOT FULL OPEN (ALB12 F06). LPV

C4.2.5 At 350°F, LOG time and date of entry into Mode 4 in the Unit Control Log Book.

10/9/88 / 1330
date/time

LPV

INITIALS

C4.2.6 Within 4 hours after entering Mode 4 and prior to reaching 325°F PERFORM the following:

a. RACK OUT and TAG both safety Injection Pump Breakers.

	UNIT 1	UNIT 2	
SI PMP-A	1AA02-16	2AA02-16	TD
SI PMP-B	1BA03-17	2BA03-17	TD

NOTE

AFWAS should be defeated to the SG Blowdown Valves, Sample Valves and MDAFW Pump Discharge Valves to accommodate MFP activities and/or SG draining/filling operations without resulting in impacting those activities.

b. At the USS's discretion, REMOVE and TAG the following fuses:

(1) Train A

(a) Auxiliary Relay Panel - Fuse Block (Allows full use of SG Blowdown valves).

UNIT 1	UNIT 2	
1ACPAR6-FU-2	2ACPAR6-FU-2	[illegible]

Removed & Tagged under clearance 1-88 10.23 — TD / IV

(b) Auxiliary Relay Panel - Fuse Block (Inhibits feed pump trip signal to initiate AFWAS).

UNIT 1	UNIT 2	
1NCPAR-2-FU-4	2NCPAR-2-FU-4	[illegible]

Removed & Tagged under 1-88-365 — [illegible] / IV

INITIALS

(2) Train B

(a) Auxiliary Relay Panel - Fuse Block (Allows full use of SG Blowdown valves),

UNIT 1	UNIT 2	
1BCPAR7-FU-6	2BCPAR7-FU-6	DK
[illegible]	[illegible]	TD IV

(b) Auxiliary Relay Panel - Fuse Block (Inhibits feed pump trip signal to initiate AFWAS),

UNIT 1	UNIT 2	
1NCPAR-4-FU-1	2NCPAR-4-FU-1	[illegible]
Removed & Tagged under 1-88-363		[illegible] IV

c. PLACE standby MDAFW Pumps handswitch in PULL-TO-LOCK. JA

d. If the TDAFW Pump is not being utilized, CLOSE HV-5122, 5125, 5127 and 5120. LPV

INITIALS

C4.2.7 When the RCS pressure is less than 377 psig, and RCS temperature is less than 340°F, PLACE at least one RHR Train in operation per 13011, "Residual Heat Removal System". LPV

a. OPERATE RHR HX Outlet Valves HV-0606(0607) and Bypass Valves FV-0618(0619) to control RCS temperature as necessary and RHR flow at a minimum total flow of 3000 gpm.

b. If applicable, PERFORM 14896, "ECCS Check Valve Cold Shutdown Inservice Test". * NA *

c. ENSURE RHR Suction Isolation surveillance is initiated each shift per 14000, "Shift And Daily Surveillance Logs". JA

CAUTION

While in Mode 5 with the Reactor Coolant Loops filled, with 1 RHR Train inoperable, the secondary side water level of at least two Steam Generators shall be greater than 17% WR.

C4.2.8 If desired, REDUCE the number of operating RCPs to one per 13003, "Reactor Coolant Pump Operation". LPV

Pump 4 is the preferred running pump to ensure best spray capability.

C4.2.9 When SG pressure falls to 25 psig INITIATE aligning Nitrogen to the SG's per 13601, "Steam Generator And Main Steam System Operation" with regulators set at 2 to 5 psig.

C4.2.10 If it is intended to perform maintenance on the RAT's during the outage, then NOTIFY Maintenance to initiate work towards backfeeding through the Main Transformer and UAT's. NA

* To be performed in MODE 5 coming out of refueling outage. Pink Sheet in MODE Change Binder. JW 10/11/80

INITIALS

C4.2.11 Either OPERATE unit systems as necessary to maintain RCS within the following parameter values or PROCEED to either Section D to continue the cooldown or 12001-C, "Unit Heatup to Hot Shutdown" to commence a heatup.

CAUTION

Ensure running RCP seal differential pressure is maintained greater than 200 psid.

RCS temperature	225 F ±10°F
RCS pressure	250 psig ±25 psig

END OF SECTION C

SECTION D: Cooldown to Cold Shutdown (less than 200°F).

NOTE

This section directs cooldown to Mode 5 and maintains temperature between 130°F and 80°F.

D4.1 PREPARATION FOR CONTINUING UNIT COOLDOWN

INITIALS

D4.1.1 If required to cool down secondary systems and break condenser vacuum, then INITIATE Section E of this procedure.

D4.1.2 COMMENCE RCS/Pressurizer pressure and temperature trending at 30 minute intervals using Data Sheet 1 and ERF Computer. (Technical Specification 4.4.9.1)

Plotting may be suspended during holds in the cooldown if the duration is expected to exceed one hour.

D4.1.3 ENSURE RHR letdown is in operation with flow rate greater than or equal to 75 gpm. LPV

D4.2 RCS COOLDOWN TO BETWEEN 130°F and 80°F

D4.2.1 COMMENCE the cooldown at a recommended rate of approximately 50°F per hour by performing the following:

a. Slowly ADJUST the RHR Outlet Valves HV-0606(0607) to reduce RCS temperature. LPV

CAUTION

Ensure running RCP seal differential pressure is maintained greater than 200 psid.

b. MAINTAIN Pressurizer pressure at 250 psig, ±25 psig, by selective use of Pressurizer Backup Heaters. LPV

INITIALS

D4.2.2 At 200°F, LOG time and date of entry into Mode 5 in the Unit Control Log Book. LPV

1724 10/07/88
time/date

D4.2.3 RACK OUT and TAG the Containment Spray pump breakers.

	UNIT 1	UNIT 2	
CS PMP A	1AA02-14	2AA02-14	JA
CS PMP B	1BA03-14	2BA03-14	JA

D4.2.4 As directed by the USS, PLACE the Containment Pre-access Purge System in operation per 13125, "Containment Purge System". [illegible]*

D4.2.5 To facilitate personnel ingress and egress, during cold shutdown, NOTIFY Maintenance to bypass the Containment Personnel Lock Interlock System.

If desired the Containment Equipment Hatch Missile Shield may be moved at this time.

D4.2.6 NOTIFY Work Planning Group to schedule and initiate mode dependent Fire Protection Surveillances. N/A **

D4.2.7 When the RCS temperature is less than 140°F, PERFORM the following:

a. If withdrawn, INSERT all Shutdown Banks to the fully inserted position. NA

b. OPEN the Reactor Trip Breakers. NA

c. STOP the CRDM Cooling Fans using the following handswitches:

CRDM UNIT - FAN 1 HS-12273A.
CRDM UNIT - FAN 2 HS-12274A.
CRDM UNIT - FAN 3 HS-12275A.
CRDM UNIT - FAN 4 HS-12276A. TNT

d. If it is intended to remain in cold shutdown for greater than 4 days, then PLACE the SG's in wet layup per 13601, "Steam Generator and Main Steam System Operation". JCB

** N/A Per FPE

INITIALS

NOTE

The RCP(s) shall be run for one or more hours after reaching the desired RCS temperature plateau to enhance SG and RCS temperature equalization. LPV

D4.2.8 When RCS temperature is less than 110°F, the remaining RCPs may be stopped per 13003, "Reactor Coolant Pump Operation". LPV

D4.2.9 If it is desired to collapse the pressurizer bubble and cooldown the pressurizer, then PERFORM the following:

a. ENSURE all CVCS Letdown Orifices are in operation. LPV

CAUTION

Expect rapid pressurizer pressure rise with charging flow greater than letdown flow at the point of going solid. Be prepared to reduce charging flow or raise letdown flow to prevent extreme pressure fluctuations.

b. RAISE pressurizer level by raising charging flow rate and/or lowering RHR letdown flow rate. LPV

c. When the pressurizer is solid as indicated by rising RCS pressure or if PIC-131 is in AUTO rising letdown flow rate, then PERFORM the following:

(1) BALANCE charging and letdown flow rates using HV-0128 and/or PIC-131 to maintain RCS pressure at 250 psig ±25 psig. LPV

INITIALS

NOTE

Charging flow may remain greater than letdown flow as a result of coolant contraction during the cooldown.

(2) Charging/RHR letdown flow rate should be adjusted so that RHR letdown purification flow is maintained greater than or equal to 75 gpm. LN

(3) OPEN Pressurizer Auxiliary Spray valve HV-8145 CD

(a) INITIATE AUX SPRAY/PRZR DELTA-T surveillance per 14915, "Special Conditions Surveillance Logs", (Technical Specification 4.4.9.2). CD *

(b) If pressurizer auxiliary spray water delta-T exceeds 320°F, then LOG the spray valve operation in the Unit Control Log and NOTIFY Engineering to log the cycle per 50040-C, "Component Cyclic or Transient Limits". CD *

(4) CLOSE the open Charging Isolation Valve HV-8146 or HV-8147. CD

(5) Continue CHARGING through the pressurizer auxiliary spray line until pressurizer steam space temperature is less than 190°F. CD

D4.2.10 MAINTAIN RCS temperature between 130°F and 80°F using RHR HX Outlet Valves HV-0606(0607). CD

NOTIFY Engineering to log the unit cooldown per 50040-C, "Component Cyclic or Transient Limits". JCB *

(STEVE LI ...) ENGINEERING NOTIFIED 10 10 88 @ 2321

INITIALS

CAUTION

Ensure all RCP's are shutdown.

D4.2.11 If it is desired to depressurize the RCS, then PERFORM the following:

a. INITIATE Lowering RCS pressure to atmospheric (50 psig as indicated on PI-408, 418, 428 or 438) using letdown pressure control PIC-131. CDS

b. When RCS pressure reaches 100 psig (150 psig as indicated on PI-408, 418, 428, 438), CLOSE all RCP Seal Leakoff Isolation valves HV-8141A, B, C, D. CD

c. ENSURE PRT nitrogen pressure is maintained greater than 0.5 psig. CD

NOTE

SI Pmp Cold Leg Isolation Valves are closed to preclude inadvertent draining of RWST to the RCS while the RCS is depressurized and partially drained.

D4.2.12 ISOLATE the Safety Injection Cold legs by performing the following:

a. CLOSE SI PMP-A TO COLD LEG ISO VLV HV-8821A. CDS

b. CLOSE SI PMP-B TO COLD LEG ISO VLV HV-8821B. CD

c. OPEN and TAG the following SI Cold Leg Isolation Valves MCC breakers:

	UNIT 1	UNIT 2	INITIALS
(1) SI PMP-A TO COLD LEG ISO VLV HV-8821A.	1ABD-15	2ABD-15	CD
(2) SI PMP-B TO COLD LEG ISO VLV HV-8821B.	1BBD-15	2BBD-15	CDS

INITIALS

CAUTION

Prior to opening the RCS to the containment atmosphere, the RCS hydrogen concentration shall be less than 5 cc/kg.

D4.2.13 When required, INITIATE RCS draining by performing the following:

a. If it is intended to drain down to perform maintenance on Reactor Head, SG's or RCP seals, then the following RCS level controls should be placed into effect:

(1) If it is intended to operate at one foot above mid-nozzle level, the preferred RHR configuration is one train operating with a flow of 3000 gpm. JT.

(2) If it is intended to operate at one foot above mid-nozzle level, a minimum of two incore thermocouples should be available during periods where the Reactor Head is installed. JB

(3) I&C should be notified to install temporary remote RCS level monitoring in the Control Room. JT.

(4) Tygon tube watch is required any time the RCS level is being changed while the RCS level is below 17% (approximately 207 feet elevation) pressurizer level. JT.

(5) Periodic comparison checks should be made every 4 hours between the Control Room Temporary RCS Level Monitors and the Tygon tube. PT

(6) The Control Room Monitors should agree within 2 percent of scale with the Tygon tube.

INITIALS

(7) Two out of three Level Monitors must agree before draining RCS below the top of the hot leg (188 feet 3 inches).

(8) If neither Control Room RCS Level Monitor is available, then a continuous Tygon tube watch should be established while RCS level is below 17% pressurizer level. PT

(9) While operating with Steam Generator Nozzle Dams installed, ENSURE one Safety Injection Pump is capable of being racked in and operated if needed.

(10) While level is in the region of the hot legs, TREND RHR Pump parameters on ERF for early detection of possible RHR Pump degradation due to vortexing.

(11) Minimum RCS level is one foot above mid-nozzle (188 feet 0 inches elevation) except for Steam Generator burping during initial drain down. For effective SG tube draining, RCS level should be lowered to 187 feet 6 inches. Upon completion of SG burping, RAISE RCS level to 188 feet - 0 inches and MAINTAIN at this level thereafter. N/A

(12) INITIATE draining the RCS per 13005, "Reactor Coolant System Draining".

INITIALS

D4.2.14 If it is intended to drain the RCS to less than 25% cold calibrate pressurizer level, then prior to reaching 25% ISOLATE potential dilution flow paths by performing the following:

a. CLOSE, LOCK and TAG the following valves:

(1) UNIT 1: CVCS ISOLATION RMW TO BA BLEND, 1-1208-U4-175 JTR

UNIT 2: CVCS ISOLATION RMW TO BA BLEND, 2-1208-U4-175 N/A

(2) UNIT 1: CVCS ISOLATION RMW TO CVCS, 1-1208-U4-177 JTR

UNIT 2: CVCS ISOLATION RMW TO CVCS, 2-1208-U4-177 N/A

b. ENSURE CLOSED, LOCKED and TAGGED the following valves:

(1) UNIT 1: CVCS OUTLET CHEM MIXING TK, 1-1208-U4-181 JTR

UNIT 2: CVCS OUTLET CHEM MIXING TK, 2-1208-U4-181 N/A

(2) UNIT 1: CVCS SUPPLY RMW TO CHEM MIXING TK, 1-1208-U4-176 JTR

UNIT 2: CVCS SUPPLY RMW TO CHEM MIXING TK, 2-1208-U4-176 N/A

INITIALS

(3) UNIT 1: CVCS FLUSH RMW TO TRN A EMERG BORATION, 1-1208-U4-183 — JTL

UNIT 2: CVCS FLUSH RMW TO TRN A EMERG BORATION, 2-1208-U4-183 — N/A

(4) UNIT 1: RMWST TO BTRS ISO, 1-1208-U6-226 — JTL

UNIT 2: RMWST TO BTRS ISO, 2-1208-U6-226 — N/A

c. When necessary, makeup to the VCT by performing the following:

(1) OPEN RWST TO CCP A & B SUCTION Valves LV-0112D and LV-0112E.

(2) CLOSE VCT OUTLET ISOLATIONS, LV-0112B and LV-0112C.

(3) ENSURE Letdown to VCT or Hold-up Tank Valve LV-0112A is in the VCT position.

(4) When VCT level has been returned to normal, OPEN LV-0112B and LV-0112C then CLOSE LV-0112D and LV-0112E.

D4.2.15 OPERATE unit systems as necessary to maintain the above conditions.

a. If required to break condenser vacuum, then PROCEED to Section E.

b. If it is intended to proceed to Mode 6, then GO to 12007-C, "Refueling Entry".

c. If it is intended to commence unit heat up, then GO to 12001-C, "Unit Heatup to Hot Shutdown".

END OF SECTION D

SECTION E. Secondary Plant Shutdown

NOTE

This section directs secondary plant activities during unit shutdown and can be used in conjunction with primary system cooldown operations.

The subsections of this section are:

E4.1 Transfer From Steam Dumps to Atmospheric Relief valves.

E4.2 Feeding Steam Generators With Condensate Pump.

E4.3 Breaking Condenser Vacuum.

E4.4 Secondary Systems activities.

E4.1 TRANSFER FROM STEAM DUMPS TO ATMOSPHERIC RELIEF VALVES

INITIALS

E4.1.1 TRANSFER to the SG Atmospheric Relief Valves by performing the following:

a. Slowly OPEN each atmospheric relief while verifying a reduced steam dump demand signal on UI-507, SH

b. VERIFY that the Steam Dump Control Valves close if PIC-507 is in AUTO or if operating in MANUAL, slowly CLOSE the Steam Dump Control Valves while opening each atmospheric relief, SH

c. When all Steam Dump Control Valves are closed, ENSURE PIC-507 is in MANUAL, SH

d. BALANCE the positions of each atmospheric relief while maintaining Tavg as desired. SH

INITIALS

E4.2 FEEDING STEAM GENERATORS WITH CONDENSATE PUMP

E4.2.1 At the USS's discretion, INITIATE feeding Steam Generators with the running Condensate Pump by performing the following:

a. VERIFY SG pressure is less than 550 psig, N/A

b VERIFY that lube oil pressure to the reset MFP and MFP Turbine Fearings is 10 to 12 psig by local indications, N/A

c. OPEN the reset MFP Discharge Valve by placing the Control Switch in OPEN-PULL-TO-LOCK at the Main Control Panel QMCB: N/A

SGFP A HS-5208,

SGFP B HS-5209.

d. If not previously performed, RESET both trains of Feedwater Isolation:

(1) HS-40049 for Train A, N/A

(2) HS-40050 for Train B. N/A

e. OPEN all BFIV's, N/A

f. CONTINUE maintaining desired SG level utilizing the BFRV's. N/A

INITIALS

E4.3 BREAKING CONDENSER VACUUM

E4.3.1 If necessary, TRANSFER the Auxiliary Steam System steam supply to the Auxiliary Boiler per 13761, "Auxiliary Steam System". SN

E4.3.2 TRANSFER the Turbine Steam Seal supply to the Auxiliary Steam Supply per 13825, "Turbine Steam Seal System". SN

E4.3.3 TRANSFER the SJAE steam supply to the Auxiliary Steam Supply per 13620, "Condenser Air Ejection System". SN

E4.3.4 CLOSE the MSIVs and Bypasses. SN

CAUTION

Breaking condenser vacuum will result in a MFPT Low Vac Trip. If AFWAS has not been defeated, then both MFPs tripped will result in a AFWAS initiation.

E4.3.5 PLACE the standby MDAFW Pump(s) Handswitches in PULL-TO-LOCK. (D)

E4.3.6 BREAK condenser vacuum and SHUT DOWN the Steam Jet Air Ejectors and the Condenser Vacuum Pumps per 13620, "Condenser Air Ejection System".

E4.3.7 PERFORM the following to reset the AFWAS signal:

a. RESET the AFWAS by resetting one MFPT Low Vacuum Trip by momentarily placing the MFPT-A(B) VAC TRIP BYPASS Handswitch to RESET position and MFPT A(B) TRIP RESET HS-3169 (3170) to the RESET position, N/A

b. If running a MDAFW Pump, then THROTTLE the AFW Flow Control Valves to the pre-initiation flow rate, N/A

INITIALS

c. If applicable, ENSURE the SG Blowdown Isolation Valves HV-7603A(B,C,D) open. N/A

E4.3.8 After the condenser pressure reaches atmospheric, SHUT DOWN the Turbine Steam Seal System per 13825, "Turbine Steam Seal System". CDS

E4.3.9 MAINTAIN the main Turbine and MFPTs on Turning Gear per 13800, "Main Turbine Operation" and 13615, "Condensate and Feedwater Systems".

E4.4 SECONDARY SYSTEM ACTIVITIES

E4.4.1 If condensate and feedwater cleanup is not anticipated, then when condensate and feedwater metal temperatures are less than 200°F, SHUT DOWN the Condensate and Feedwater System per 13615, Condensate And Feedwater Systems". KED

E4.4.2 NOTIFY Chemistry and SHUT DOWN the Condensate Filter Demineralizer System per 13616, "Condensate Filter Demineralizer System". KED

E4.4.3 If the secondary outage is planned to exceed 10 days, then PERFORM the following:

a. When condensate and feedwater metal temperature is between 90°F and 200°F, COORDINATE with Chemistry and PLACE the Feedwater Heaters in wet layup. CDS

b. When Turbine metal temperatures reach ambient, REMOVE Turbine from Turning Gear per 13800, "Main Turbine Operation". KED

c. During the unit outage, once a week, PLACE the Turbine on Turning Gear for 4 to 6 hours.

INITIALS

E4.4.4 If required, PLACE a steam blanket on the MSRs per 13800, "Main Turbine Operation". N/A

E4.4.5 If required, for Condenser Waterbox or Circulating Water System maintenance, SHUT DOWN the Circulating Water System per 13724, "Circulating Water System". KED

If required for maintenance or inspection, then INITIATE draining of the Condenser Waterboxes per 13724, "Circulating Water System". CTS

E4.4.6 If main generator maintenance or inspection is planned, then INITIATE purging the main generator per 13810, "Generator Gas System". KED

If hydrogen atmosphere is to be maintained, then MINIMIZE usage during the outage by reducing hydrogen pressure to not less than 5 psig.

E4.4.7 SHUT DOWN the Isophase Bus Duct Cooling System by performing the following:

a. At 480V AC SWGR NB03, OPEN Isophase Bus Duct Heater Breaker

UNIT 1: 1NB03-16, KED

UNIT 2: 2NB03-16. KED

b. At local Panel PLCB, STOP the running fan using HS-16550 for Fan No. 1 and/or HS-16551 for Fan No. 2.

Completed KE Drawdy 10/19/88 / 2049
Signature Date/Time

Reviewed [signature] 10-19-88 / 2052
Signature Date/Time

Comments ______________________
____
____
____

5.0 REFERENCES

5.1 PROCEDURES

5.1.1 10006-C, "Reactor Trip Review"

5.1.2 12001-C, "Unit Heatup To Hot Shutdown"

5.1.3 12002-C, "Unit Heatup To Normal Operating Temperature And Pressure"

5.1.4 12003-C, "Reactor Startup"

5.1.5 13003, "Reactor Coolant Pump Operation"

5.1.6 13005, "Reactor Coolant System Draining"

5.1.7 13006, "Chemical And Volume Control System Startup And Normal Operation"

5.1.8 13007, "VCT Gas Control And RCS Chemical Addition"

5.1.9 13009, "CVCS Reactor Makeup Control System"

5.1.10 13010, "Boron Thermal Regeneration System"

5.1.11 13011, "Residual Heat Removal System"

5.1.12 13120, "Containment Building Cooling Systems"

5.1.13 13125, "Containment Purge System"

5.1.14 13601, "Steam Generator And Main Steam System Operation"

5.1.15 13605, "Steam Generator Blowdown Processing System"

5.1.16 13610, "Auxiliary Feedwater System"

5.1.17 1361[illegible], "Condensate And Feedwater Systems"

5.1.18 13616, "Condensate Filter Demineralizer System"

5.1.19 13617, "Feedwater Heater Extraction, Vent And Drain System"

5.1.20 13620, "Condenser Air Ejection System"

5.1.21 13724, "Circulating Water System"

5.1.22 13760, "Auxiliary Steam Boiler System"

5.1.23 13761, "Auxiliary Steam System"

5.1.24 13800, "Main Turbine Operation"

5.1.25 13810, "Generator Gas System"

5.1.26 13825, "Turbine Steam Seal System"

5.1.27 14000, "Operations Shift and Daily Surveillance Logs"

5.1.28 14005, "Shutdown Margin Calculations"

5.1.29 14748, "AFW Check Valve Cold Shutdown Inservice Test"

5.1.30 14915, "Special Conditions Surveillance Logs"

5.1.31 24695, "N.I. System Source Range Channel Calibration"

5.1.32 24696, "N.I. System Source Range Channel Calibration"

END OF PROCEDURE TEXT

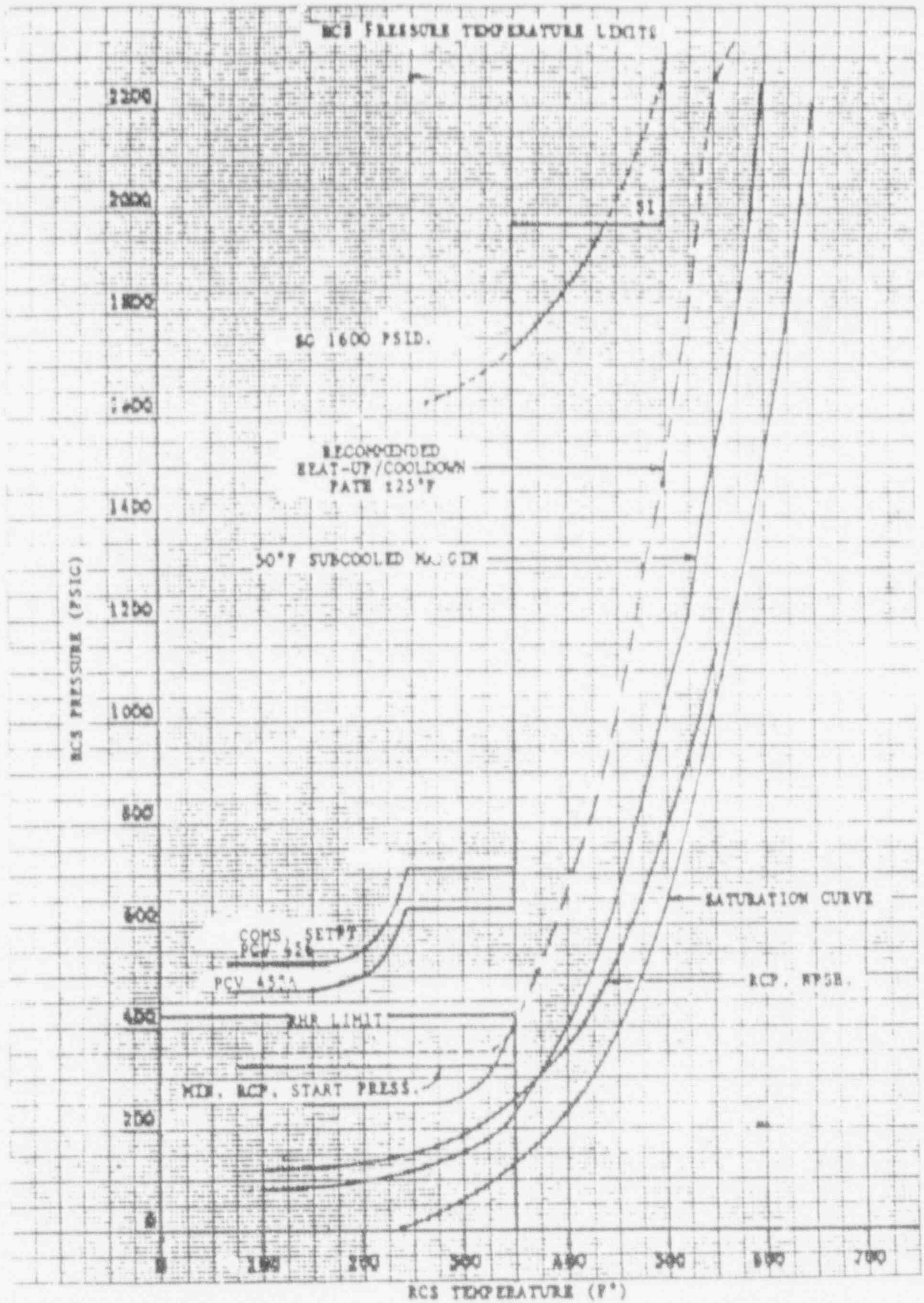


FIGURE 1 - RCS PRESSURE TEMPERATURE LIMITS

Sheet 1 of 1

UNIT NO. ONE DATE 10 / 9 / 88

RCS/PRZR TEMPERATURE AND PRESSURE

DATA SHEET 1

TIME	Lowest Channel of TI-0413B TI-0423B TI-0433B TI-0443B RCS TEMP	TI-0454 PRZR TEMP	PI-438LR or PI-405WR PRZR PRESS	PRZR/RCS DELTA T
0345	555	635	2235	80
0415	550	635	2220	85
0445	540	635	2215	95
0515	530	635	2160	105
0545	530	615	1900	85
0615	535	620	1900	85
0645	530	620	1925	90
0715	530	620	1950	90
0745	530	620	1950	90
0815	530	620	1950	90
0845	530	620	1910	90
0915	515	610	1750	95
0945	499	590	1530	91
1015	470	570	1310	100
1045	450	545	1016	95

Completed LL Vannier 10/09/88 1051
Signature Date/Time

Reviewed 10-12-88
Signature Date/Time

Comments none

PROCEDURE NO	REVISION	PAGE NO
VEGP 12006-C	9	41 of 41

Sheet 1 of 1

UNIT NO. ONE DATE 10/09/88

RCS/PRZR TEMPERATURE AND PRESSURE

DATA SHEET 1

TIME	Lowest Channel of TI-0413B TI-0423B TI-0433B TI-0443B RCS TEMP	TI-0454 PRZR TEMP	PI-438LR or PI-405WR PRZR PRESS	PRZR/RCS DELTA T
1115	425	528	895	103
1145	400	500	665	100
1215	370	LSV 10/9/88 ~~525~~ 470	535	100
1245	370	470	590	100
LAG 10/9 ~~1334~~ 1315	353	~~505~~ 453	~~5~~ 435	100
1345	343	440	360	97
1415	330	435	350	105
1445	325	430	335	105
1515	315	420	325	105
1545	305	410	305	105
1615	290	410	290	120
1645	240	400	265	160
1715	210	390	250	180
1745	190	380	248	190
1815	175	380	250	205

Completed [signature] 10.9.88 / 1817
Signature Date/Time

Reviewed [signature] 10/12/88 2054
Signature Date/Time

Comments NONE

*03445

Sheet 1 of 1

UNIT NO. ONE

DATE 0/9/88

RCS/PRZR TEMPERATURE AND PRESSURE

DATA SHEET 1

TIME	Lowest Channel of TI-0413B TI-0423B TI-0433B TI-0443B RCS TEMP	TI-0454 PRZR TEMP	PI-438LR or PI-405WR PRZR PRESS	PRZR/RCS DELTA T
1845	150	380	250	230
1915	140	380	~~200~~ 250	240
1945	135	380	250	245
2015	130	375	250	245
2045	130	370	250	240
* 2115	130	370	250	240
2145	130	370	250	240
2215	130	370	250	240
2245	125	395	300	270
2315	125	395	300	270
2345	120	390	300	270
0015	115	390	300	275
0045	115	390	300	275
0115	115	390	300	275
**				

Completed ____________ Signature 10-10-88 / 0115 Date/Time

Reviewed ____________ Signature 10/12/88 2056 Date/Time

Comments * COOLDOWN AWAITING START OF SECOND TRAIN RHR (Hx BYPASS VALVE CONTROLLER PROBLEMS). ** RCS COOLDOWN STABILIZED, AWAITING I&C REPAIR OF 'A' TRAIN RHR Hx BYPASS VALVE

Sheet 1 of 1

UNIT NO. One DATE 10/10/88

RCS/PRZR TEMPERATURE AND PRESSURE

DATA SHEET 1

TIME	Lowest Channel of TI-0413B TI-0423B TI-0433B TI-0443B RCS TEMP	TI-0454 PRZR TEMP	PI-438LR or PI-405WR PRZR PRESS	PRZR/RCS DELTA T
1145	120	390	260	270
1215	110	390	265	280
1245	103	395	268	292
1315	95	395	250	300
**				

Completed LPVannin 10-10-88 1320
Signature Date/Time

Reviewed [illegible] 10/12/88 2057
Signature Date/Time

Comments ** This condition Stabilized Here

PROCEDURE NO.	REVISION	PAGE NO.
VEGP 10000-C	12	26 of 26

PLANT VOGTLE UNITS 1 & 2

TECH SPEC INTERPRETATION

RCS COLD SHUTDOWN - LOOPS FILLED

TECH SPEC #: 3.4.1.4

QUESTION OR AREA NEEDING CLARIFICATION:

What does "with reactor coolant loops filled" mean?

INTERPRETATION:

We will consider loops filled when pressurizer cold cal level is maintained ≥ 25% and RCS is vented per 13001.

ie use LCO 3.4.1.4.2 for MODE 5 with reactor coolant loops not filled when RCS is drained below 25% pressurizer cold cal level or steam generator tubes have not been vented.

Approved By: W. F. Kitchens 2/22/89
Manager Operations Date

xc: Manager Operations
Nuclear Safety & Compliance Manager
Engineering Support Manager
Plant Training & Emergency Prepardness Manager
Required Reading Book

FIGURE 2

Approval	Vogtle Electric Generating Plant NUCLEAR OPERATIONS	Georgia Power	Procedure No. 10019-C
W F Kitchens			Revision No. 4
Date 1/31/88	Unit COMMON		Page No. 1 of 3

VOID

CONTROL OF SAFETY RELATED LOCKED VALVES

1.0 PURPOSE

This procedure identifies the administrative controls for valves which are important for Safety Related Systems that shall be locked in a specified position.

2.0 DEFINITIONS

2.1 LOCKED VALVE

A valve whose operation is prevented by a chain and padlock arrangement or other positive locking device.

2.2 KEY CONTROL

Keys required for plant operation are controlled in accordance with 00008-C, "Plant Lock And Key Control".

3.0 RESPONSIBILITIES

The Shift Supervisor shall maintain administrative control of the keys used for locking of Safety Related System valves. (The Support Shift Supervisor normally implements this procedure for the Unit Shift Supervisors.)

4.0 PRECAUTIONS

The status of locked valves shall not be changed without prior authorization by the Shift Supervisor.

5.0 INSTRUCTIONS

5.1 BASIC CONTROL OF LOCKED VALVES

5.1.1 The initial status of valve positions and locking devices is established by system valve lineups that are performed following an outage.

5.1.2 The valves listed in 11867-C, "Locked Valve Verification Checklist" shall be locked in the specified position with the specified padlocks using lengths of chain or other positive locking devices.

5.1.3 Locks should be placed on the remote operator for those manual valves that have remote operators such as reach rods.

5.1.4 In the cases where it is not feasible to physically lock the apparatus, a Hold Tag may be used.

5.1.5 When a locked component is unlocked for operational purposes, the lock and chain should, if possible, be locked to adjacent components so as to preclude loss.

5.1.6 If the locking device cannot be affixed at the component, it should be returned to the Shift Supervisor for disposition.

5.1.7 Status changes in the positions of locked valves shall be documented by use of 11868-1, "Locked Valve Manipulation Log".

5.1.8 The position and lock status of each locked valve will be verified quarterly and recorded per 11867-C, "Locked Valve Verification Checklist".

5.1.9 Padlocks and chains should not normally be removed to verify position of locked valves. If locks must be removed, then re-installation must be independently verified.

5.2 MISPOSITIONED VALVES/INOPERABLE LOCKING DEVICES

NOTE

Valves in position other than the required position due to the provisions of Sub-subsection 5.1.5 are not considered mispositioned.

5.2.1 If any locked valve is discovered in a position other than the required position or a valve locking device is found inoperable, the operator shall NOTIFY the Shift Supervisor.

5.2.2 The Shift Supervisor shall:

a. PERFORM an evaluation to determine if the valves current position has resulted in any adverse system conditions,

b. PERFORM an evaluation to determine whether repositioning the valve to its correct configuration will result in any adverse system conditions,

c. Based on an acceptable evaluation, DIRECT the repositioning and locking of the affected valve or if unacceptable, shall INITIATE placing the component/systems affected in a position where the valve can be restored to its correct configuration,

d. ENSURE a Deficiency Card per 00150-C, "Deficiency Control" has been initiated.

6.0 REFERENCES

6.1 PROCEDURES

6.1.1 00008-C, "Plant Lock And Key Control"

6.1.2 00150-C, "Deficiency Control"

6.1.3 00308-C, "Independent Verification Policy"

6.1.4 00304-C, "Equipment Clearance And Tagging"

6.1.5 11888-1, "Locked Valve Manipulation Log"

6.1.6 11867-C, "Locked Valve Verification Checklist

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

JUL 1 9 1991

Docket Nos. 50-424, 50-425
License Nos. NPF-68, NPF-81

Georgia Power Company
ATTN: Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
P. O. Box 1295
Birmingham, AL 35201

Gentlemen:

SUBJECT: NRC INSPECTION REPORT NOS. 50-424/91-14 AND 50-425/91-14

This refers to the inspection conducted by Steven Vias and Scott Sparks of this office on June 17-21, 1991, and June 24-28, 1991. This inspection included a review of activities authorized for your Vogtle facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed inspection report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Within the scope of the inspection, no violations or deviations were identified.

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

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

Sincerely,

George A Belisle for

Alan R. Herdt, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Enclosure:
NRC Inspection Report

cc w/encl: (See page 2)

9108160090

cc w/encl:
R. P. McDonald
Executive Vice President-Nuclear
Operations
Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

C. K. McCoy
Vice President-Nuclear
Georgia Power Company
P. O. 1295
Birmingham, AL 35201

W. B. Shipman
General Manager, Nuclear Operations
Georgia Power Company
P. O. 1600
Waynesboro, GA 30830

J. A. Bailey
Manager-Licensing
Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

D. Kirkland, III, Counsel
Office of the Consumer's
Utility Council
Suite 225, 32 Peachtree Street, NE
Atlanta, GA 30302

Office of Planning and Budget
Room 615B
270 Washington Street, SW
Atlanta, GA 30334

Office of the County Commissioner
Burke County Commission
Waynesboro, GA 30830

Joe D. Tanner, Commissioner
Department of Natural Resources
205 Butler Street, SE, Suite 1252
Atlanta, GA 30334

Thomas Hill, Manager
Radioactive Materials Program
Department of Natural Resources
878 Peachtree St., NE., Room 600
Atlanta, GA 30309

(cc w/encl cont'd - see page 3)

cc w/encl: (Continued)
Attorney General
Law Department
132 Judicial Building
Atlanta, GA 30334

Dan Smith, Program Director
of Power Production
Oglethorpe Power Corporation
2100 East Exchange Place
P. O. Box 1349
Tucker, GA 30085-1349

Charles A. Patrizia, Esq.
Paul, Hastings, Janofsky & Walker
12th Floor
1050 Connecticut Avenue, NW
Washington, D. C. 20036

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

Report No.: 50-424/91-14 and 50-425/91-14

Licensee: Georgia Power Company
P.O. Box 1295
Birmingham, AL 35201

Docket No.: 50-424 and 50-425 License Nos.: NPF-68 and NPF-81

Facility Name: Vogtle 1 and 2

Inspection Conducted: June 17-21, 1991, and June 24-28, 1991

Inspectors: S. J. Vias 7/19/91
S. J. Vias, Project Engineer Date Signed

S. J. Vias 7/19/91
for S. E. Sparks, Project Engineer Date Signed

Approved By: P. H. Skinner 7/19/91
P. Skinner, Chief Date Signed
Reactor Projects Section 3B
Division of Reactor Projects

SUMMARY

Scope: This routine inspection entailed review of open items and concerns from the NRC Inspection Report 424,425/90-19 and other management directives.

Results: In the areas inspected, violations or deviations were not identified.

9108160095

DETAILS

1. Persons Contacted

Licensee Employees

*S. Allison, Shift Supervisor
*H. Beacher, Senior Engineer
*J. Beasley, Manager Operations
S. Chestnut, Manager Technical Support
*C. Christiansen, Safety Audit and Engineering Group Supervisor
*C. Coursey, Maintenance Superintendent
*T. Greene, Assistant General Manager Plant Support
M. Hobbs, I&C Superintendent
*W. Kitchens, Assistant General Manager Plant Operations
E. Kovinsky, Shift Superintendent (Training)
P. Johnson, Health and Safety Coordinator
*R. Legrand, Manager Health Physics and Chemistry
W. Lyon, Quality Concern Program Coordinator
*R. Mansfield, Plant Engineering Supervisor
*M. Sheibani, Nuclear Safety and Compliance Supervisor - Acting
*W. Shipman, General Manager Nuclear Plant
*C. Stinespring, Manager Plant Administration
C. Williams, Shift Superintendent

Other licensee employees contacted included technicians, supervisor, engineers, operators, maintenance personnel, quality control inspectors, and office personnel.

NRC Resident Inspectors

*B. Bonser
*D. Starkey
*P. Balmain

*Attended Exit Interview

An alphabetical list of acronyms and abbreviations is listed in the last paragraph of the inspection report.

2. Review of Administrative Directives

a. 10 CFR 50.59 Review Process Related to Procedures and Procedure Changes.

Licensee Administrative Procedure 00056-C, Safety and Environmental Evaluation, requires that 10CFR50.59 evaluations must be prepared for new procedures, procedure revisions and procedure deletions. Standard forms are provided to perform these reviews. The inspectors reviewed a sample of revised and new procedures and found that a

50.59 evaluation was perform in each case and that the guidelines were being adhered to.

b. Operator Guidance for Entry into TS Conditions.

During the OSI it was noted that there was a concern regarding the level of guidance provided to operators on TS entry conditions, knowledge of TS bases, and overall management philosophy toward TS entry and TS violations. To address the areas of TS guidance and knowledge of TS bases, the inspectors verified through training department interviews that specific training is dedicated to TS and their bases. A separate week in training is devoted entirely to TS review. Additionally, the licensee recently revised the method in Administrative Procedure 10000-C, Conduct of Operations, by which licensee TS clarifications are reviewed and approved. TS clarifications now require review and concurrence of the Technical Support Manager and approval by the Manager Operations. The inspectors have not detected any weaknesses in operator knowledge or use of TS.

c. Management Philosophy on TS Action Statements.

Management philosophy for entry into TS LCO actions are routinely discussed with resident inspectors concurrent with various levels of plant management when unusual plant conditions which necessitate this action occurs. The inspectors have observed several examples of conscientious, deliberate efforts by the licensee to adhere to the intent of TS usage. Three specific examples were noted in March 1991, and discussed in detail in Inspection Report 50-424, 425/91-05 where the licensee found it necessary to clarify or evaluate TSs for continued operation. These three evaluations were all associated with a leak on a Unit 2 steam generator. In all three cases the licensee's clarifications were assessed as safe and conservative. These examples were particularly noteworthy because they all involved weighing safety factors against economic factors. The licensee has also revised their TS clarification document. This document which provides guidance to operators on TS that require further interpretation is now reviewed by the Technical Support Manager in addition to the review and approval by the Operations Manager. This additional review provides independent review by a licensed individual.

d. The Deficiency Card Process.

When a suspected deficiency has been identified, a DC is submitted to the control room within one hour. The unit shift supervisor then reviews the DC to determine the need for immediate reporting and other reviews. The DC is then submitted to Engineering Technical Support where it is also reviewed for reportability and to determine whether a deficiency exists.

If Engineering Technical Support determines the identified deficiency is reportable then Engineering Technical Support is designated as the lead department responsible for dispositicning the deficiency. If the DC does not require a written report, then it is forwarded to the responsible department for action. The responsible department screens the DC in accordance with guidance on root cause determination and provides a brief explanation to indicate why a RCCA evaluation is or is not required.

There are three categories of events detailed in Administrative Procedure 00150-C, Deficiency Control. The first two categories of events are more serious type events and require a multi-disciplined review to ensure a complete, thorough, unbiased investigation. Included in these two categories of events are: unplanned reactor trips, unplanned ESF actuations, significant radiological events, unplanned turbine trips, diesel generator valid failures, discovery of significant damage to a major plant component, and other events identified by site management. The third category of events could be considered a precursor to a more significant event but, due to its less significant nature, would not typically require a multi-disciplined review.

For Category 1 events a multi-desciplined Event Investigation Team investigates the event and prepares a report which includes a root cause determination. For category 2 and 3 events the responsible department manager will assign an appropriately qualified individual within the department to perform the root cause determination. For category 2 events the responsible department manager will also identify additional departments to perform a simultaneous root cause determination. The additional departments will return their results to the lead department for preparation of a combined final root cause determination.

For category 2 or 3 events the individual assigned by the department manager to perform the root cause determination, may be the same individual who dispositions the DC. The lead responsible department manager is required to concur with the identified root causes and corrective actions. After completion by the department manager, the Engineering Technical Support department will review the DC to ensure an adequate investigation and that corrective actions detailed are appropriate. The inspectors did not find any examples where this process was not properly followed.

e. Availability of Control Documents for Scheduling Activities in the Control Room.

The inspectors have found that during outage and non-outage periods, a Plan Of The Day is available in the control room which details planned activities for the day. The information in the POD is accurate. The POD provides a weekly surveillance schedule for both units, time lines for significant work to be accomplished, a listing of the work orders to complete and other useful information. Also information on detailed work scheduling is disseminated through several meetings held during the day which the shift superintendent attends. This information is then passed on to the control room personnel.

f. Direction of ROs and SROs from Management.

In the area of management direction of RO's and SRO's, the inspectors have questioned a number of licensed operators about their perspective toward having a questioning attitude. It was determined that operators are encouraged by management through formal training and on the job activities to have a questioning attitude and not to arbitrarily accept the directive of a supervisor or manager if there is a question as to the correctness of that directive.

g. Independent Review Process of "Functional Tests".

A functional test is defined in the Vogtle administrative procedure, Equipment Clearance and Tagging, as a test of a component or subsystem to verify satisfactory operation of the component or subsystem, after the component or subsystem has been placed in a configuration that assures plant equipment and personnel safety. A functional test is performed by qualified craft personnel for certain maintenance activities such as troubleshooting, fan balancing, MOVATS testing, and valve operational checks, etc. Before any functional test can be authorized, all other individuals that need to use the clearance for maintenance, must sign a release acknowledging the functional test is being performed. At this point the unit shift supervisor must ensure that all signatures are obtained before authorizing the functional test. During the review of the process by the inspectors, it was observed through the procedures in place, that the functional test to be performed gets adequate independent review.

h. Method of Making "Clearances" by Control Room Operators.

Equipment clearances and tagging are handled by the SSS, who is a licensed SRO and is part of the Operations shift. The SSS works with the control room/unit shift supervisors and keeps them informed of any clearances being worked. The clearance/tagging responsibilities of the SSS include: reviewing the impact of a clearance on plant operations; authorizing clearance installation and removal; and preparing and/or authorizing Functional Tests and Partial Releases.

The SSS may perform all clearance and tagging functions as designee for the USS as long as the SSS is cognizant of the unit configuration. The SSS must notify the reactor operator that a safety related system is being removed from service. The inspectors in reviewing the clearance logs found no indication of problems in this area.

3. Follow-up on Previously Identified Items (92701) (92702)

   a. (Closed) VIO 50-424,425/90-19-01: Failure to Perform Calibrations of Surveillance Requirement 4.2.5.3 Resulting in Incorrect RCS Flow Measurements.

      This violation was issued due to a failure to calibrate feedwater temperature instrumentation used during the performance of the precision heat balance required by TS 4.2.5.3. The information from the heat balance is used in the determination of RCS flow measurements. As stated in the licensee's response dated February 8, 1991, the violation occurred due to their incorrect interpretation that the TS did not require calibration of permanently installed instrumentation when performing a precision heat balance.

      The inspectors verified the licensee's corrective actions, which included a revision of procedure 88075-C, Precision Heat Balance, to require calibration of feedwater temperature computer points. In addition, RCS flow rates were re-calculated and determined to be acceptable. Based on a review of the above corrective actions, this violation is closed.

   b. (Closed) VIO 50-424,425/90-19-02: Inadequate Surveillance Procedure Results in a Failure to Maintain Containment Isolation as Required by TS 3.6.3.

      This violation was issued due to failure to comply with an LCO when CIVs were opened and, thus inoperable during surveillance testing of the hydrogen monitor system. The inspectors verified the licensee's corrective actions as stated in their response dated February 8, 1991. These included a revision to procedures 24551-1 and 2, Containment Hydrogen Monitor Train A Analog Channel Operational Test and Channel Calibration, and procedures 24552-1 and 2 (Train B), to eliminate the need to open the subject CIVs. In addition, the licensee submitted a TS amendment, which if approved would allow the subject valves to be opened periodically under administrative control without entering the LCO. The inspectors consider the licensee's corrective actions to be satisfactory.

   c. (Closed) IFI 50-424,425/90-19-03 (Weakness No. 1): Review Licensee's Method for TS Interpretations.

      This item was identified due to the licensee's method of allowing the Operations Manager to be solely responsible for the approval and distribution of the TS interpretations. The inspectors reviewed the licensee's response to this item, dated February 8, 1991. The licensee agreed that it would be beneficial to perform additional reviews of TS interpretations to ensure that the intent of TS do not change. The licensee revised procedure 10000-C, Technical Specification Clarifications, to include the concurrence of the Manager, Technical Support, on all TS Clarification requests. In addition, the Manager, Technical Support is responsible for obtaining the appropriate departmental reviews, including licensing personnel. The inspectors verified that recent TS Clarifications received multiple department reviews, and that controlled copies of TS Clarifications were complete and distributed in a controlled manner. The inspectors verified that the licensee also performed a review of all current TS interpretations to ensure a change of intent did not occur.

d. (Closed) IFI 50-424,425/90-19-04 (Weakness No. 2): Review Licensee's Method for Interdepartmental Procedure Review.

This weakness was identified due to a lack of Operations Department review of Surveillance Procedure 24551-2, Containment Hydrogen Monitor Analog Operability Test and Channel Calibration. The licensee's method for interdepartmental procedure review appeared to rely on the procedure writer's judgment.

The licensee's response to this item stated that Administrative Procedure 00051-C, Procedure Review and Approval, requires that the department procedure coordinators obtain intra- and interdepartmental reviews, as necessary, for technical content, accuracy, and completeness. Comments are solicited from department managers. Procedures which affect areas of responsibility of other departments are required to be reviewed by the affected departments. Verification is also required to be obtained from all departments affected.

The inspectors reviewed procedure 00051-C, and determined that requirements and responsibilities for procedure review were defined. Review of recent LERs, and discussions with the Resident Inspectors did not identify any recent procedural problems which could be attributed to a lack of or improper interdepartmental review. The inspectors also noted that the licensee held departmental briefings on the event concerning procedure 24551-2, and emphasized the importance of obtaining a proper review. The inspectors concluded that the lack of review for procedure 24551-2 was an isolated incident.

e. (Closed) IFI 50-424,425/90-19-05 (Weakness No. 3): Voluntary Entry in TS LCO.

This weakness was identified due to a concern that the licensee was voluntarily entering into LCOs unnecessarily to reduce the scope of the subsequent refueling outage. The inspectors reviewed the LCO entry log book in the main control room, which contains a brief summary of each TS LCO entered, the reason for the entry, and entry and exit times. In addition, the main control room Design Change

Package log book was also reviewed by the inspectors. These reviews did not identify any LCOs which were entered to reduce subsequent work scope or for other inappropriate reasons. The inspectors discussed this issue with an Operations Shift Supervisor, who indicated a heightened sensitivity to this type of issue. This issue was also discussed with the resident inspector staff, who stated that voluntary entry into an LCO is closely evaluated by the residents and the licensee. Based on the above actions, this item is closed.

f. (Closed) IFI 50-424,425/90-19-06 (Weakness No. 4): Licensee Interpretation of TS LCO Shutdown Action Time.

This weakness was identified due to the licensee's position that TS 3.0.3 allowed a subsequent reduction in power three hours after entry into the LCO. This position was based on the ability to go from Mode 1 to Mode 4 within four hours. During the OSI in August 1990, the team identified that certain actions discussed in Generic Letter 87-09 were not fully implemented, i.e., notification of the load dispatcher within the first hour and a controlled shutdown within the next six hours.

The licensee's response included a clarification of their position on entry into TS LCO 3.0.3. In summary, the licensee's position states that upon entry in TS 3.0.3, the Unit Shift Supervisor should evaluate plant conditions and formulate a course of action including actions to prepare for and complete a safe and controlled shutdown. In cases where a high degree of confidence that the technical issues can be resolved or repairs made promptly to restore component operability, an immediate power reduction is not advisable. However, actions are to be taken to ensure that an orderly shutdown will be completed within the allowable time while repairs or attempts to resolve operability are underway. Within the first hour, notifications to the load dispatcher and management should be made. If the condition still exists, power reduction should begin no later than four hours into the action (three hours of the allowable time remaining). In those cases where it is apparent that resolution of the condition will not occur within the allowable time, an orderly shutdown will begin immediately.

The licensee's clarification of TS 3.0.3 entry is issued as a TS Clarification, and maintained in the main control room. This issue was discussed with Operations personnel, who indicated a heightened awareness to activities due to entry into TS 3.0.3. In addition, this area is followed by the resident inspector staff during normal operational safety verifications, who indicated no recent problems associated with entry in TS 3.0.3. Based on the above actions, this item is closed.

g. (Closed) IFI 50-424,425/90-19-07 (Weakness No. 5): Certification of Qualifications for Plant Equipment Operators.

This weakness was identified due to the licensee's practice of training evaluators delegating the responsibility for evaluating performance of trainee PEO rounds to a qualified PEO. In addition, it was noted that the licensee does not perform a management review of the implementation of on-the-job training for PEOs.

The inspectors determined from discussions with the licensee and from their response to the weakness that their policy is to have evaluators accompany trainee PEOs on rounds. Evaluators were also reminded of their responsibility in these areas as a result of the identified weakness. The inspectors also verified management involvement in the review of on-the-job training for PEOs. As part of the Management Observation Program, a specific module was recently added in which the trainee and the evaluator are observed by line management at all levels. Results of these observations are provided to the Assistant Plant Manager, Operations. The inspectors concluded the licensee actions in these areas were satisfactory.

h. (Closed) IFI 50-424,425/90-19-08 (Weakness No. 6): Procedures for Defining Minimum Acceptable Performance of Plant Equipment Operator General Inspections.

This item was identified due to observed inconsistencies in the performance of PEO general inspections. The licensee revised procedure 10001-C, Logkeeping, to provide guidance on minimum acceptable standards for PEO rounds. Discussions with the licensee indicated this area was reviewed as part of the requalification training for PEOs, where minimum acceptable standards are specified. In addition, the licensee added an additional Support Shift Supervisor to each operating shift whose responsibilities include observation of rounds performed by PEOs, plant walkdowns, and plant material conditions. This program enhancement will minimize inconsistencies with PEO general inspections. Based on this action, this item is closed.

i. (Closed) IFI 50-424,425/90-19-09 (Weakness No. 7): Method for Authorizing Overtime.

The inspectors reviewed the licensee's activities to address weaknesses identified in the authorization of overtime. Plant management reemphasized the adherence to Administrative Procedure 00005-C, Overtime Authorization, through a memorandum from the General Manager to all department managers, superintendents, and supervisors. The inspectors reviewed overtime authorizations for the recent Unit 2 refueling outage and verified that time in excess of the guidelines was properly authorized by the department manager and reviewed by the plant manager or designee. In addition, overtime did not appear to become routine. Discussions with plant management indicated that tighter controls were imposed on overtime allowed prior to the recent Unit 2 outage. An additional concern identified in the 50-424,425/90-19 Inspection Report was that the non-supervisory staffing policy had the potential to result in unbalanced experience levels on the night shifts. Plant management indicated a sensitivity to this issue, and agreed that the potential existed. However, staffing is frequently reviewed to ensure that the proper number of qualified personnel are on site at all times. In addition, management stated that any potential or actual problems attributed to unbalanced experience levels would be identified and corrected. Based on this review, this item is closed.

j. (Closed) IFI 50-424,425/90-19-10 (Weakness No. 8): Review Licensee's Method of Holding Periodic Mini-Safety Meetings for Operations Personnel.

Administrative procedure 00250-C, Safety Committee and General Safety Meeting, provides guidance on mini-safety meetings. The inspectors verified the licensee distributes a bimonthly safety newsletter to all department managers with a list of selected topics for discussion. Each department utilizes a signoff on the back of the newsletter to list the names of personnel who attended the mini-safety meetings. This information is trended to ensure individual managers periodically hold mini-safety meetings. The licensee stated that the Operations Department usually holds mini-safety meetings as a part of shift turnover. The inspectors considered the licensee's actions in this area to be satisfactory.

k. (Closed) IFI 50-424,425/90-19-11 (Weakness No. 9): Review Licensee's Method for Implementing the Quality Concern Program.

This concern was identified due to the licensee not performing an exit interview with each exiting employee to solicit quality concerns. In addition, a concern was identified in that the assignment of investigations to parties directly involved was a potential conflict of interest.

Discussions with the Quality Concern Coordinator indicated that effort is made to perform an exit interview with each employee. However, if this is not possible, an employee is requested to complete a confidential Quality Concern form as part of the normal termination process. This form is then forwarded to the Quality Concern Coordinator for review. In addition, attempts are made to contact each employee by written correspondence or by telephone if an exit interview cannot be performed.

The inspectors also discussed the potential conflict of interest with the Quality Concern Coordinator, who stated that the review cycle minimizes the potential for any conflict of interest. After a quality concern has been identified and investigated, the Coordinator reviews the documentation to ensure a thorough review. This documentation is then forwarded to the Assistant Plant Manager, Plant Support, for an additional review.

Based on the above review, the inspectors concluded the licensee's Quality Concern Program adequately addresses the previously identified concerns. Based on this action, this item is closed.

1. (Closed) VIO 50-424,425/90-05-01, Failure to Mechanically Secure Valve 1-1208-U4-176 During Mode 5 As Required By TS 3.4.1.4.2.C.

   On February 26, 1990. while Unit 1 was in Mode 5 with reactor coolant loops not filled, the inspector discovered that RMWST discharge valve, 1-1208-U4-176, was closed but was not mechanically secured as required by TS 3.4.1.4.2.C. Instead of a chain and lock, the valve had a clearance hold tag which provided only administrative control to preclude valve operation.

   The locked valve procedure, 10019-C, was revised to eliminate utilization of a "hold tag" on valves that are required by TS to be secured in position. The licensee conducted a review of valves which are required by TS to be secured to ensure that a mechanical locking mechanism was in place. The licensee committed in their response dated May 24, 1990, to provide an appropriate locking mechanism for those valves, if any, which are secured by hold tags and are required to be secured by TS. The review identified no other valves which fell into that category. For the specific valve discussed in this violation, a steel cable was routed through drilled holes in the valve handle then mechanically secured to prevent operation of the valve.

No violations or deviations were identified.

4. Exit Meeting

The inspection scope and findings were summarized on June 28, 1991, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

5. Acronyms and Abbreviations

CIV	Containment Isolation Valve
DC	Deficiency Card
ESF	Engineered Safety Features
IFI	Inspector Follow-up Item
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MOVATS	Motor Operated Valve Analysis and Testing System
OSI	Operational Safety Inspection
PEO	Plant Equipment Operator
RCCA	Root Cause and Corrective Actions
RO	Reactor Operator
SRO	Senior Reactor Operator
SSS	Shift Support Supervisor
TS	Technical Specifications
VIO	Violation

NORMS

CLEARANCE SHEET

CLEARANCE # 1-88-371

Equipment/System/Number: CVCS Blender Makeup Valves 1208

Reason For Clearance: Isolate RMW to RCS per UOP 12006

Estimated Outage Time: N/A Work Order #: N/A

Requested Date/Time: N/A Needed Date/Time: N/A

Requested by: John Bowles Extension: 3001

Involves Tech. Spec. or Safety-Related Item: No___ Yes X

Locked Valves: No___ Yes X Prepared By C Sitler

Fire Protection Impaired No X Yes___ Reviewed By [illegible signature]

Authorized by: [illegible signature] Date: 10-11-88 Time: 0542

Installed by: [illegible signature] Date: 10-11-88 Time: 0918

Verified by: Richard L Chavez Date: 10-11-88 Time: 1053

SUBCLEARANCES

NAME
Printed in first space
Signature in second space

GROUNDING DEVICES VERIFIED REMOVED AND SUBCLEARANCE RELEASED BY:

PRINTED AND SIGNATURE	WORK DOC	EXT	DATE	TIME	SIGNATURE	DATE	TIME
1.							
2.							
3.	No Subclearance Holders						
4.							
5.							

Subclearance Continuation Sheet Attached?	Yes	NO ✓

CLEARANCE REMOVAL:

Authorized by: [illegible signature] Date: 11-15-88 Time: 0710

Removed by: Graham Wood Date: 11-15-88 Time: 0900

Verified by: [illegible signature] Date: 11-15-88 Time: 0910

FRONT
Figure 3a
(TYPICAL)

Sheet 1 of 1

CLEARANCE #: 1-88-371 REFERENCES UOP 12006

PREPARED BY C Sattler

	Equipment To be Cleared and Tagged.				Tags To Be Removed And Equipment Returned to Service as Specified.		
	Tag No.	Equipment Name and Number	Position	Init/Init(1)	Rem. Seq.	Position	Init/Init(1)
RA47	1	1-1208-U4-175 RMW to Blender	Locked closed	[illegible] / RDC	1	OPEN	AFW / [illegible]
RA47	2	1-1208-U4-177 RMW to CVCS	Locked Closed	[illegible] / RDC	2	OPEN	AFW / [illegible]
RA?G	3	1-1208-U4-181 Chem mixing tank outlet	Locked Closed	[illegible] / RDC	3	SHUT	AFW / [illegible]
RA47	4	1-1208-U4-176 RMW to Chem mix tank	Locked closed	[illegible] / RDC	4	SHUT	AFW / [illegible]
RA47	5	1-1208-U4-183 RMW to train "A" Emergency boration	locked closed	[illegible] / RDC	5	LC	AFW / [illegible]
A-08	6	1-1208-U6-226 RMW to BTRS	locked closed	[illegible] / RDC	6	LC	AFW / [illegible]
				/			/
				/			/
				/			/
				/			/
				/			/
				/			/

COMMENTS:

(1) Second Initials are for Independent Verification.

BACK
FIGURE 4 CLEARANCE SHEET
(TYPICAL)

FUNCTIONAL TEST FORM

CLEARANCE # 188371

EQUIPMENT TO BE TESTED CHEM ADD TNK TO CVCS

REQUESTED BY

REASON FOR TEST ADD Hydrazine Remx TEST DOCUMENT NO.

CLEARANCE POINTS TO BE RELEASED

Tag No.	Equipment No.	Req'd. Pos.	Init.
2	1-1208-U4-177	CLOSED	[illegible]
4	1-1208-U4-176	CLOSED	[illegible]
3	1-1208-U4-181	CLOSED	[illegible]

CLEARANCE RESTORATION

Sequence	Pos.	Init.	Init.
3	LC	[illegible]	[illegible]
4	LC	[illegible]	[illegible]
2	LC	[illegible]	[illegible]

SUBCLEARANCE RELEASE FOR TEST

	TIME	DATE

CLEARANCE ALIGNMENT RESTORED W. Hyer TIME 0415 DATE 10-12-88

VERIFIED BY [illegible] TIME 0415 DATE 10/12/88

TEST ALIGNMENT PERFORMED BY [illegible] TIME 0310 DATE 10/12/88

SHIFT SUPERVISOR PERMISSION TO PERFORM TEST W. Hyer TIME 0250 DATE 10-12-88

Figure 5

703445

VOID

VCT GAS CONTROL AND RCS CHEMICAL ADDITION

FOR INFORMATION ONLY

1.0 PURPOSE

This procedure provides instructions for Volume Control Tank (VCT) gas control operations and for Reactor Coolant System chemical addition. Instructions are included in the following sections:

4.1 Aligning VCT Hydrogen Purge - Normal Operation

4.2 Establishing A Nitrogen Blanket In The VCT

4.3 Transferring From A Nitrogen To A Hydrogen Atmosphere In The VCT

4.4 Transferring From A Hydrogen To A Nitrogen Atmosphere In The VCT - Nitrogen Supplied From N2 Supply Header

4.5 Transferring From A Hydrogen To A Nitrogen Atmosphere In The VCT - Nitrogen Supplied From The GWPS

4.6 Oxygen Or Ammonia Removal From VCT Gas Space

4.7 Reactor Coolant System Chemical Addition

2.0 PRECAUTIONS AND LIMITATIONS

2.1 Do not smoke, strike sparks or allow open flames in the vicinity of hydrogen lines.

2.2 When a Reactor Coolant Pump is operating, maintain a minimum backpressure of 15 psig on the No. 1 seal by maintaining a pressure of at least 18 psig in the Volume Control Tank.

2.3 Explosive mixtures of oxygen and hydrogen in the Volume Control Tank must be avoided at all times. The oxygen concentration must not exceed 5% by volume when hydrogen is present.

2.4 The reactor coolant temperature must be less than 180°F when adding hydrazine. For oxygen scavenging, the reactor coolant temperature should be between 150°F and 180°F.

2.5 When adding hydrazine the Demineralizers should be bypassed and letdown flow diverted directly to the Volume Control Tank.

3.0 PREREQUISITES OR INITIAL CONDITIONS

3.1 A level is established in the VCT and makeup is available.

3.2 The Gaseous Waste Processing System (GWPS) is available for waste processing.

3.3 The Auxiliary Gas Systems - Nitrogen and Hydrogen - are available to supply cover gas to the VCT.

3.4 The Nuclear Sampling Systems - Liquid and Gaseous - are available for sampling the VCT.

3.5 The Reactor Makeup Water System is aligned to supply water to the Chemical Mixing Tank.

3.6 The Nuclear Sampling Panel 1-1215-P5-NSP has been aligned by the Chemistry Department.

4.0 INSTRUCTIONS

4.1 ALIGNING VCT HYDROGEN PURGE - NORMAL OPERATION

CAUTION

If the VCT oxygen concentration limit is approached, the oxygen content should be lowered per Subsection 4.6.

NOTE

If a nitrogen atmosphere exists in the VCT, align the tank for hydrogen purge operation per Subsection 4.3.

4.1.1 REQUEST Chemistry to verify, by sample analysis, that the oxygen concentration in the VCT gas space is less than 5% by volume.

4.1.2 VERIFY that a hydrogen atmosphere exists in the VCT as follows:

a. VCT Hydrogen Manifold Isolation 1-1208-U4-107 is OPEN,

b. VCT Nitrogen Manifold Isolation 1-1208-U4-108 is CLOSED,

c. Waste Gas Decay Shutdown Tank Supply To VCT, 1-1208-U4-352, is CLOSED.

4.1.3 ENSURE that VCT Hydrogen Regulator 1-PCV-8156 is set to 18 psig or greater

4.1.4 ENSURE the Gaseous Waste Processing System in operation, aligned to a Normal Gas Decay Tank, per 13201-1, "Gaseous Waste Processing System".

4.1.5 ENSURE that the VCT Purge Flow Controller 1-HIC-1094 is set at zero.

4.1.6 OPEN the VCT TO GWPS ISO VLV 1-PV-115.

4.1.7 ADJUST the VCT Purge Flow Controller 1-HIC-1094 to 0.7 scfm.

4.1.8 VERIFY that VCT pressure is 18 psig or greater on 1-PI-0115.

4.2 ESTABLISHING A NITROGEN BLANKET IN THE VCT

NOTE

This subsection should be used to establish a nitrogen blanket if the VCT has been opened to atmosphere.

4.2.1 CLOSE the VCT Hydrogen Manifold Isolation 1-1208-U4-107.

4.2.2 VERIFY that VCT Nitrogen Regulator 1-PCV-8155 is set to 15-20 psig.

4.2.3 OPEN the VCT Nitrogen Manifold Isolation 1-1208-U4-108. Independent Verification required.

4.2.4 REQUEST Chemistry to verify, by sample analysis, the VCT oxygen concentration.

4.2.5 If oxygen concentration is greater than 5%, PERFORM the following:

a. CLOSE VCT NITROGEN MANIFOLD ISOLATION 1-1208-U4-108,

b. REMOVE cap and OPEN GWPS Vent Header Sample Line Vent 1-1208-X4-374,

CAUTION

Do not exceed VCT pressure of 65 psig.

c. START manual makeup to the VCT per 13009-1, "CVCS Reactor Makeup Control System",

d. RAISE level in the VCT to 95 - 100%, then STOP makeup,

e. CLOSE GWPS Vent Header Sample Line Vent 1-1208-X4-374,

f. OPEN VCT NITROGEN MANIFOLD ISOLATION 1-1208-U4-108,

g. OPEN Chemical Volume Control System (CVCS) Drain VCT To Recycle Holdup Tank (RHT) 1-1208-U4-123 and LOWER VCT level to 45 - 50% then CLOSE drain,

h. REPEAT Sub-subsection 4.2.4 and 4.2.5 until the VCT oxygen concentration is less than 5% by volume,

i. VERIFY 1-1208-U4-123 is CLOSED. Independent verification required,

j. VERIFY 1-1208-X4-374 is CLOSED and cap installed. Independent verification required.

4.2.6 SET the VCT Nitrogen Regulator 1-PCV-8155 to at 18-20 psig.

4.2.7 PLACE the CVCS Reactor Makeup System in AUTO per 13009-1, "CVCS Reactor Makeup Control System".

4.3 TRANSFERRING FROM A NITROGEN TO A HYDROGEN ATMOSPHERE IN THE VCT

CAUTION

If the VCT oxygen concentration limit is approached, the oxygen content should be lowered per Subsection 4.6.

NOTE

This procedure should be performed in conjunction with unit heatup.

4.3.1 ALIGN a Shutdown Gas Decay Tank (S/D GDT) to receive VCT purge:

a. If a S/D GDT is not in service, ALIGN the system per 13201-1, "Gaseous Waste Processing System",

b. If the S/D GDT is in service supplying Unit 2, ALIGN the Unit 2 system to receive Unit 1 VCT purge per 13201-2, "Gaseous Waste Processing System".

CAUTION

VCT pressure must be maintained at greater than 18 psig to maintain adequate backpressure on Reactor Coolant Pump Seals.

4.3.2 MONITOR VCT pressure indicated by 1-PI-115.

a. If VCT pressure approaches 18 psig, CLOSE VCT TO GWPS ISO VLV 1-PV-115,

b. INCREASE the setpoint on the inservice VCT Nitrogen Regulator 1-PCV-8155 or A-PCV-7891 prior to re-establishing flow.

4.3.3 OPEN the VCT TO GWPS ISO VLV 1-PV-115.

4.3.4 ADJUST the VCT Purge Flow Controller 1-HIC-1094 to establish a purge flow of slightly less than 1.2 scfm.

4.3.5 RAISE VCT level to approximately 95% as follows:

a. If Reactor Coolant System heatup is in progress, ALLOW the reactor coolant expansion to raise the VCT level by placing Letdown To VCT or Holdup Tank Valve 1-LV-112A in the VCT position,

b. If Reactor Coolant System heatup is not in progress, PLACE Letdown To VCT or Holdup Tank Valve 1-LV-112A in the VCT position and RAISE level in the VCT by operation of the Reactor Makeup Control System in MANUAL per 13009-1, "CVCS Reactor Makeup Control System".

4.3.5 When VCT level reaches approximately 95%, STOP makeup to the VCT if applicable and PLACE 1-LV-112A to the Holdup Tank (HUT) position to lower level, and ESTABLISH a hydrogen supply to the VCT as follows:

a. ENSURE that VCT Hydrogen Regulator 1-PCV-8156 is set to at least 18 psig,

b. OPEN the VCT Hydrogen Manifold Isolation 1-1208-U4-107; independent verification required,

c. CLOSE the VCT Nitrogen Manifold Isolation 1-1208-U4-108; independent verification required,

d. CLOSE the VCT Waste Gas Decay Shutdown Tanks Supply To VCT 1-1208-U4-352; independent verification required.

4.3.7 LOWER the VCT level to 30 - 50% while maintaining a cover gas pressure of at least 18 psig as indicated on 1-PI-115.

4.3.8 RAISE the VCT level to 95% as follows:

a. If RCS heatup is in progress, ALLOW the RCS expansion to raise level by placing 1-LV-112A to the VCT position,

b. If RCS heatup is not in progress, PLACE 1-LV-112A to the VCT position and RAISE level per 13009-1, "CVCS Reactor Makeup Control System".

4.3.9 When VCT level reaches 95%, STOP Reactor Makeup System if applicable, and PLACE 1-LV-112A to the HUT position.

4.3.10 LOWER VCT level to 30 - 50% while maintaining a cover gas pressure of 18 psig as indicated on 1-PI-115.

4.3.11 REQUEST Chemistry to sample the VCT gas space.

4.3.12 REPEAT Sub-subsections 4.3.8 through 4.3.10 if necessary, until the VCT gas concentration is in specification.

4.3.13 ESTABLISH normal VCT level and:

a. PLACE 1-LV-112A in AUTO,

b. PLACE CVCS Reactor Makeup Control System in AUTO per 13009-1, "CVCS Reactor Makeup Control System".

4.3.14 ALIGN the Gaseous Waste Processing System for operation using a Normal Gas Decay Tank per 13201-1, "Gaseous Waste Processing System".

4.4 TRANSFERRING FROM A HYDROGEN TO A NITROGEN ATMOSPHERE IN THE VCT - NITROGEN SUPPLIED FROM N2 SUPPLY HEADER

NOTE

This subsection should be used if VCT nitrogen purge gas cannot be supplied from the Shutdown Gas Decay Tank.

4.4.1 ALIGN a Shutdown Gas Decay Tank (S/D GDT) to receive VCT purge as follows:

a. If a S/D GDT is not in service, ALIGN the system per 13201-1, "Gaseous Waste Processing System",

b. If the S/D GDT is in service supplying Unit 2, ALIGN the Unit 2 system to receive Unit 1 VCT purge per 13201-2, "Gaseous Waste Processing System".

4.4.2 ADJUST VCT Purge Flow Controller 1-HIC-1094 to raise the hydrogen purge flow to the Gaseous Waste Processing System to slightly less than 1.2 scfm.

4.4.3 ENSURE that VCT Nitrogen Regulator 1-PCV-8155 is set to 18-20 psig. <

4.4.4 OPEN the VCT Nitrogen Manifold Isolation 1-1208-U4-108. Independent verification required.

4.4.5 CLOSE the VCT Hydrogen Manifold Isolation 1-1208-U4-107. Independent verification required.

4.4.6 VERIFY that the VCT pressure is being maintained at 18 psig or greater as indicated by 1-PI-115.

NOTE

Continue the purge flow through the VCT until sample analyses indicate the hydrogen concentration in the reactor coolant has been decreased to less than 5 cc/kg.

4.4.7 When the Reactor Coolant System hydrogen concentration is below 5cc/Kg, DISCONTINUE the purge flow through the VCT as follows:

a. ADJUST VCT Purge Flow Controller 1-HIC-1094 for zero flow,

b. CLOSE the VCT TO GWPS ISO VLV 1-PV-115.

4.4.8 If required, ALIGN the Gaseous Waste Processing System for operation using a Normal Gas Decay Tank, otherwise SHUT DOWN the system per 13201-1, "Gaseous Waste Processing System".

4.5 TRANSFERRING FROM A HYDROGEN TO A NITROGEN ATMOSPHERE IN THE VCT - NITROGEN SUPPLIED FROM THE GWPS

NOTE

This procedure should be performed in conjunction with unit cooldowns when the VCT nitrogen purge gas is being supplied from the GWPS.

4.5.1 ALIGN a Shutdown Gas Decay Tank to receive VCT purge as follows:

a. If a S/D GDT is not in service, ALIGN the system per 13201-1, "Gaseous Waste Processing",

b. If the S/D GDT is is service supplying Unit 2, ALIGN the Unit 2 system to receive Unit 1 VCT purge per 13201-2, "Gaseous Waste Processing System".

4.5.2 ADJUST 1-HIC-1094 to raise the hydrogen purge flow to the Gaseous Waste Processing System to slightly less than 1.2 scfm.

4.5.3 ENSURE that Shutdown Gas Decay Tank to VCT Regulator A-PCV-7891 is set to 18-20 psig.

4.5.4 OPEN the GWPS ISO N2 PURGE FROM WASTE DECAY S/D TK TO VCT A-1902-U4-128. Independent verification required.

4.5.5 OPEN the CVCS VCT WGD S/D TANKS SUPPLY TO VCT 1-1208-U4-352. Independent verification required.

4.5.6 CLOSE the VCT Hydrogen Manifold Isolation 1-1208-U4-107. Independent verification required.

4.5.7 VERIFY that the VCT pressure is being maintained at 18 psig as indicated on 1-PI-115.

NOTE

Continue the purge flow through the VCT until sample analyses indicate the hydrogen concentration in the reactor coolant has been lowered to less than 5 cc/kg.

4.5.8 When the Reactor Coolant System hydrogen concentration is below 5 cc/Kg, DISCONTINUE the purge flow through the VCT as follows:

a. ADJUST VCT Purge Flow Controller 1-HIC-1094 for zero flow,

b. CLOSE the VCT TO GWPS ISO VLV 1-PV-115.

4.5.9 ALIGN the nitrogen supply regulator to the VCT and discontinue the purge from the Shutdown Gas Decay Tank as follows:

a. ENSURE that the VCT Nitrogen Regulator 1-PCV-8155 is set to 18-20 psig,

b. OPEN the VCT Nitrogen Manifold Isolation 1-1208-U4-108. Independent verification required,

c. CLOSE the CVCS VCT WGD S/D TANKS SUPPLY TO VCT 1-1208-U4-352. Independent verification required,

d. If not required for Unit 2 operations, CLOSE the GWPS ISO N2 PURGE FROM WASTE DECAY S/D TK TO VCT Isolation Valve, A-1902-U4-128. Independent Verification required.

4.5.10 VERIFY that the VCT pressure is being maintained at 18-20 psig as indicated on 1-PI-115.

4.5.11 If required, ALIGN the Gaseous Waste Processing System for operation using a Normal Gas Decay Tank, otherwise shutdown the system per 13201-1, "Gaseous Waste Processing System".

4.6 OXYGEN OR AMMONIA REMOVAL FROM VCT GAS SPACE

CAUTION

If the Shutdown Gas Decay, Tanks are being used as the purge supply for the Unit 2 VCT, shift purge supply to the nitrogen regulator per 13007-2, "VCT Gas Control And RCS Chemical Addition", prior to performing this procedure.

4.6.1 ENSURE the following valves are CLOSED:

a. GWPS VCT WGD S/D TANKS SUPPLY TO VCT 1-1208-U4-352,

b. GWPS VCT WGD S/D TANKS SUPPLY TO VCT 2-1208-U4-352,

c. GWPS ISO N2 PURGE FROM WASTE DECAY S/D TK TO VCT Isolation Valve A-1902-U4-128.

4.6.2 ALIGN a Shutdown Gas Decay Tank to receive VCT purge as follows:

a. If a S/D GDT is not is service, ALIGN the system per 13201-1, "Gaseous Waste Processing System",

b. If the S/D GDT is in service supplying Unit 2, ALIGN the system to receive Unit 1 purge per 13201-2, "Gaseous Waste Processing".

4.6.3 ENSURE that VCT Nitrogen Regulator 1-PCV-8155 is set to 18-20psig.

4.6.4 ENSURE the VCT Nitrogen Manifold Isolation 1-1208-U4-108 is OPEN.

4.6.5 ENSURE that VCT Purge Flow Controller 1-HIC-1094 is set for zero flow.

CAUTION

VCT pressure must be greater than 18 psig to maintain adequate backpressure on Reactor Coolant Pump Seals.

4.6.6 MONITOR VCT pressure indicated by 1-PI-115.

a. If VCT pressure approaches 18 psig, CLOSE the VCT To GWPS Isolation Valve 1-PV-115,

b. RAISE the setpoint on VCT Nitrogen Regulator PCV-8155 prior to re-establishing flow.

4.6.7 OPEN the following valves:

a. VCT To GWPS Isolation Valve, 1-PV-115,

b. VCT Purge Flow Controller 1-HIC-1094 to establish a purge flow of slightly less than 1.2 scfm.

4.6.8 RAISE VCT level to 90 - 95% as follows:

a. PLACE Letdown to VCT or Holdup Tank Valve, LV-112A to the VCT position,

b. RAISE level in the VCT by operation of the Reactor Makeup Control System in MANUAL per 13009-1, "CVCS Reactor Makeup Control System".

CAUTION

Do not allow VCT level to decrease below 30%.

4.6.9 When VCT level reaches 90%, PLACE Letdown to VCT or Holdup Tank Valve 1-LV-112A to the HUT position to decrease level, and isolate the purge to the Gaseous Waste Processing System as follows:

a. CLOSE the VCT TO GWPS ISO VLV 1-PV-115,

b. Continue to divert water to the Recycle Holdup Tank until VCT level is 30 - 50%.

4.6.10 When VCT level reaches approximately 50%, PLACE Letdown to VCT or Holdup Tank Valve 1-LV-112A to AUTO.

4.6.11 REQUEST Chemistry to sample the VCT gas space.

CAUTION

Do not exceed a Shutdown Gas Decay Tank pressure of 80 psig.

4.6.12 REPEAT Sub-subsections 4.6.8 through 4.6.11, if necessary, until the VCT gas concentration is in specification.

4.6.13 If the Unit 2 VCT purge supply was transferred from Shutdown Gas Decay Tank to nitrogen regulator at the beginning of this subsection, then PERFORM the following:

a. REQUEST Chemistry to sample Shutdown Gas Decay Tank and if acceptable for Unit 2 VCT purge supply,

b. TRANSFER the Unit 2 VCT purge supply from nitrogen regulator to Shutdown Gas Decay Tank per 13007-2, "VCT Gas Control And RCS Chemical Addition".

4.7 REACTOR COOLANT SYSTEM CHEMICAL ADDITION

NOTE

To ensure thorough mixing, at least one Reactor Coolant Pump should be in operation while chemicals are being added to the system.

4.7.1 ISOLATE the Chemical Mixing Tank by verifying the following valves are CLOSED:

a. Chemical Mixing Tank Supply From RMWST 1-1208-U4-176,

b. Chemical Mixing Tank Outlet Valve, 1-1208-U4-181.

CAUTION

When adding chemicals, a face shield, gloves and protective clothing must be worn. Inhalation of, or skin contact with chemicals such as lithium hydroxide or hydrazine should be avoided.

4.7.2 COORDINATE with Chemistry to add the chemicals to the Chemical Mixing Tank per 35110-C, "Chemistry Control Of The Reactor Coolant System".

CAUTION

Tank filling should be performed slowly to prevent the overflow of chemicals from the tank vent.

4.7.3 OPEN Chemical Mixing Tank Supply From RMWST 1-1208-U4-176, approximately one eighth turn, to slowly fill the tank.

4.7.4 When water starts to flow out of the tank vent, CLOSE Chemical Mixing Tank Vent 1-1208-U4-179.

4.7.5 Fully OPEN Chemical Mixing Tank Supply From RMWST 1-1208-U4-176.

CAUTION

When adding hydrazine, the Demineralizers should be bypassed and letdown flow diverted directly to the VCT.

4.7.6 If adding hydrazine, PLACE Letdown to Demineralizer/VCT Valve 1-TV-0129 to the VCT position.

4.7.8 OPEN Chemical Mixing Tank Outlet Valve 1-1208-U4-181.

4.7.9 ALLOW flow through the Chemical Mixing Tank for ten minutes, then ISOLATE and DEPRESSURIZE the tank as follows:

a. CLOSE Chemical Mixing Tank Outlet Valve 1-1208U4-181. Independent verification required,

b. CLOSE Chemical Mixing Tank Inlet Valve 1-1208-U4176. Independent verification required,

c. Slowly OPEN Chemical Mixing Tank Outlet Drain 1-1208-U4-180 and RELIEVE the tank pressure, then CLOSE the valve.

4.7.12 After approximately one hour, REQUEST Chemistry to sample the Reactor Coolant System and REPEAT the chemical addition if necessary.

5.0 REFERENCES

5.1 PROCEDURES

5.1.1	13006-1,	"CVCS Startup And Normal Operation"
5.1.2	13009-1,	"CVCS Reactor Makeup Control System"
5.1.3	13012-1,	"Nuclear Sampling System - Liquid"
5.1.4	13013-1,	"Nuclear Sampling System - Gaseous"
5.1.5	13201-1,	"Gaseous Waste Processing System"
5.1.6	13707-C,	"Auxiliary Gas System - Nitrogen"
5.1.7	13708-C,	"Auxiliary Gas System - Hydrogen"
5.1.8	13733-1,	"Reactor Makeup Water System"
5.1.9	35110-C,	"Chemistry Control Of The Reactor Coolant System"
5.1.10	13007-2,	"VCT Gas Control And RCS Chemical Addition"

5.2 P&ID's

5.2.1	1X4DB115,	Chemical & Volume Control System
5.2.2	1X4DB116-1,	Chemical & Volume Control System
5.2.3	1X4DB128,	Waste Processing System-Gas
5.2.4	1X4DB129,	Waste Processing System-Gas
5.2.5	1X4DB140,	Nuclear Sampling System-Liquid
5.2.6	1X4DB141,	Nuclear Sampling System-Gaseous

5.3 Alvin W. Vogtle Units 1 & 2, Precautions, Limitations and Setpoints Document for Nuclear Steam Supply Systems.

END OF PROCEDURE TEXT

1-88-371

EQUIPMENT TO BE TESTED Chem Add to CVCS

REQUESTED BY C. Adams

REASON FOR TEST Add Hyd Peroxide TEST DOCUMENT NO. N/A

CLEARANCE POINTS TO BE RELEASED

Tag No.	Equipment No.	Req'd. Pos.	Init.
02	1-1208-U4-177	closed	[illegible]
04	1-1208-U4-176	closed	[illegible]
03	1-1208-U4-181	closed	[illegible]

CLEARANCE RESTORATION

Sequence	Pos.	Init.	Init.
3	L.C.	[illegible]	[illegible]
2	L.C.	[illegible]	[illegible]
1	L.C.	[illegible]	[illegible]

SUBCLEARANCE RELEASE FOR TEST — TIME — DATE

N/A

CLEARANCE ALIGNMENT RESTORED W [illegible] TIME 0722 DATE 10/12/88

VERIFIED BY [illegible] TIME 1130 DATE 10/12/88

TEST ALIGNMENT PERFORMED BY W [illegible] TIME 0705 DATE 10/12/88

SHIFT SUPERVISOR PERMISSION TO PERFORM TEST
[illegible] TIME 0625 DATE 10-12-88

Figure 5

FUNCTIONAL TEST FORM

CLEARANCE # 1-88-371

EQUIPMENT TO BE TESTED Chem Add Tank to VCT

REQUESTED BY

REASON FOR TEST Add H_2 Peroxide TEST DOCUMENT NO. N/A

CLEARANCE POINTS TO BE RELEASED

Tag No.	Equipment No.	Req'd. Pos.	Init.
02	1-1208-U4-177	closed	EPE
04	1-1208-U4-176	closed	EPE
03	1-1208-U4-181	closed	EPE

CLEARANCE RESTORATION

Sequence	Pos.	Init.	Init.
3	LC	EPE	RFW
2	LC	EPE	AEL
1	LC	EPE	RFW

SUBCLEARANCE RELEASE FOR TEST

	TIME	DATE
N/A	N/A	N/A

CLEARANCE ALIGNMENT RESTORED EPEAVES TIME 1034 DATE 10-13-88

VERIFIED BY [illegible] TIME 1155 DATE 10-13-88

TEST ALIGNMENT PERFORMED BY E.P.EAVES TIME 1030 DATE 10-13-88

SHIFT SUPERVISOR PERMISSION TO PERFORM TEST [illegible] TIME 0937 DATE 10-13-88

Figure 5

FUNCTIONAL TEST FORM

CLEARANCE # 1-88-371

EQUIPMENT TO BE TESTED chem add tank to VCT

REQUESTED BY

REASON FOR TEST add H2 peroxide TEST DOCUMENT NO. N/A

CLEARANCE POINTS TO BE RELEASED

Tag No.	Equipment No.	Req'd. Pos.	Init.
2	1-1208-U4-177	CL	DCC
4	1-1208-U4-176	CL	DCC
3	1-1208-U4-181	CL	DCC

CLEARANCE RESTORATION

Sequence	Pos.	Init.	Init.
3	LC	DCC	JJ
2	LC	DCC	JJ
1	LC	DCC	JJ

SUBCLEARANCE RELEASE FOR TEST

	TIME	DATE
N/A		

CLEARANCE ALIGNMENT RESTORED

	TIME	DATE
D C Cain	16:53	10-13-88

VERIFIED BY	TIME	DATE
J Jackson	10:49	11-6-88

TEST ALIGNMENT PERFORMED BY D C Cain TIME 1638 DATE 10-13-88

SHIFT SUPERVISOR PERMISSION TO PERFORM TEST

J J Barr TIME 1554 DATE 10-13-88

Figure 5

EXHIBIT 14

Chemical Addition Evolution
Chronology of
Significant Events

October 11, 1988 (all times are in Central Time)	
About 5:30 p.m.	The Night Shift crew began duty with Mr. Jimmy Paul Cash as OSOS and Mr. John Bowles as Unit Shift Supervisor.
About 7:00 p.m.	Preparations for (or the initiation of) nitrogen injection into the steam generators began.
October 12, 1988	
1:50 a.m.	Nitrogen injection into the steam generators was completed.
About 3:00 a.m.	The Support Shift Supervisor, Mr. Tom Ryan, authorized and completed a Functional Test Form to release Clearance No. 1-88-371 from RMWST discharge Valves Nos. 176, 177 and 181.
About 3:30 a.m.	RCS water level was at 189' 10".
4:00 a.m.	Mr. Ryan supervised plant personnel who added hydrogen peroxide to the Chemical Mixing Tank and then filled up the tank with water from the RMWST (the chemicals were not injected into the RCS). Mr. Bowles recorded the "0400" entry in the Shift Supervisor Log.
4:15 a.m.	Clearance No. 1-88-371 was restored to RMWST discharge Valve Nos. 176, 177 and 181.
Between 5:07 a.m. and 5:33 a.m.	The Day Shift arrived in the Control Room. Mr. John Hopkins was the OSOS and Mr. Jeffrey Casser was the Unit Shift Supervisor. A discussion of the applicability of Tech. Spec. § 3.4.1.4.2 occurred and Mr. Bowles recorded the "LE 0400" late entry in the Shift Supervisor Log.

Between 5:07 a.m. and 6:00 a.m.	Mr. Hopkins and Mr. Gasser discussed Tech. Spec § 3.4.1.(2 with Mr. W. F. Kitchens, the Operations Manager, in the Control Room. Mr. Kitchens instructed Mr. Hopkins to suspend the chemical addition evolution.
6:00 a.m.	The OSOS/outage status meeting took place, attended by the OSOS, the Outage & Planning Manager, Mr. Kitchens and numerous others, at which the status of the outage in general was discussed and the fact that the chemi addition evolution was on hold pendin review of Tech. Specs.
About 6:10 a.m.	Following the OSOS/outage status meeting, Messrs. Kitchens and Hopkins reviewed the Tech. Spec. and the FSAR and spoke with Mr. Walter Marsh, the Deputy Manager of Operations.
6:25 a.m.	Messrs. Hopkins and Gasser authorized the release of Clearance No. 1-88-371 on RMWST discharge Valve Nos. 176, 177 and 181 and directed shift personnel to open the valves for no more than five minutes.
7:05 a.m. through 7:09 a.m.	RMWST discharge Valve Nos. 176, 177 and 181 were in the open position.
7:22 a.m.	Clearance No. 1-88-371 was restored to RMWST discharge Valve Nos. 176, 177 and 181.

<u>October 13, 1988</u>

9:37 a.m.	Messrs. Hopkins and Gasser authorized the release of Clearance No. 1-88-371 on RMWST discharge Valve Nos. 176, 177 and 181 and directed shift personnel to open the valves for no more than five minutes.
10:30 a.m. through 10:34 a.m.	RMWST discharge Valve Nos. 176, 177 and 181 were in the open position.
10:34 a.m.	Clearance No. 1-88-371 was restored to RMWST discharge Valve Nos. 176, 177 and 181.
3:59 p.m.	Messrs. Hopkins and Gasser authorized the release of Clearance No. 1-88-371 on RMWST discharge Valve Nos. 176, 177 and 181 and

	directed shift personnel to open the valves for no more than five minutes.
4:40 p.m. through 4:44 p.m.	RMWST discharge Valve Nos. 176, 177 and 181 were in the open position.
4:53 p.m.	Clearance No. 1-88-371 was restored to RMWST discharge Valve Nos. 176, 177 and 181.

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

JUN 15 1989

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

Georgia Power Company
ATTN: Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
P. O. Box 1295
Birmingham, AL 35201

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-424/89-14 AND 50-425/89-15)

This refers to the Nuclear Regulatory Commission (NRC) inspection conducted by Messrs. J. F. Rogge and R. F. Aiello, on March 18 - May 5, 1989. The inspection included a review of activities authorized for your Vogtle facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed Inspection Report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

The inspection findings indicate that certain activities appeared to violate NRC requirements. The violation, references to pertinent requirements, and elements to be included in your response are presented in the enclosed Notice of Violation.

The enclosed Inspection Report also identifies activities that appeared to violate NRC requirements but are not being cited; therefore, no response is required for these items.

In accordance with Section 2.790 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations, a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

The responses directed by this letter and its enclosures are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

8906280127

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

Sincerely,

Alan R. Herdt

Alan R. Herdt, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Enclosures:
1. Notice of Violation
2. Inspection Report

cc w/encls:
R. P. McDonald, Executive Vice President - Nuclear Operations
C. K. McCoy, Vice President - Nuclear
G. R. Fredrick, Quality Assurance Site Manager
G. Bockhold, Jr., General Manager Nuclear Plant
J. A. Bailey, Manager - Licensing
G. W. Churchill, Esquire, Shaw, Pittman, Potts, and Trowbridge
J. E. Joiner, Esquire, Troutman, Sanders, Lockerman, and Ashmore
D. Kirkland III, Counsel, Office of the Consumer's Utility Council
State of Georgia

ENCLOSURE 1

NOTICE OF VIOLATION

Georgia Power Company
Vogtle, Units 1 and 2

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

During the Nuclear Regulatory Commission (NRC) inspection conducted on March 18 - May 5, 1989, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1988), the violation is listed below.

10 CFR Part 50, Appendix B, Criterion V, states that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

Technical Specification 6.7.1.a requires that written procedures be established, implemented, and maintained covering activities delineated in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

Contrary to the above, six examples were identified where the licensee failed to appropriately establish or implement procedures as follows:

1. On April 28, 1989, following an NRC inspection of a major portion of the control rooms and TSC drawings, the inspector identified that administrative procedure 00101-C, "Drawing Control," Step 3.4.4, and engineering procedure 50009-C, "As-Built Notices," Step 4.6.3, were not implemented in that the primary safety-related drawing's as-built notices were not ensured of drawing legibility prior to distribution.

2. On April 2, 1989, the inspector identified that operations procedure 12004-C, "Power Operation," Steps 4.1.3.g and 4.1.4, were not implemented in that the licensee failed to open all four Unit 2 bypass feed isolation valves and failed to stabilize #3 Steam Generator level prior to placing the bypass feed regulation valve in automatic.

3. On April 3, 1989, following a feedwater isolation, the licensee identified that startup test procedure 2-6AB-01, "Dynamic Automatic Steam Dump Control," was not adequately established in that attachment 10.5 incorrectly specified the wrong polarity for a test input signal which resulted in six steam dumps opening fully. This procedure error was identical to an error discovered during the Unit 1 startup test program.

4. On April 7, 1989, following a feedwater isolation on Unit 2, the licensee identified that a failure to implement procedure 12004-C, "Power Operation," Step 4.1.3, had occurred in that long-cycle feedwater recirculation cleanup was not secured which resulted in all four steam generators being cross connected. This condition lasted until a level imbalance resulted in a feedwater isolation.

5. On March 26, 1989, the licensee identified a failure to adequately establish procedures 13105-1 and 13105-2, "Safety Injection System," in that the procedure for filling accumulators resulted in the inoperability of the safety injection flow path during Mode 3 operation. This procedure was utilized on nine occasions on Unit 1 and one occasion on Unit 2.

6. On December 8, 1988, with Unit 1 at 100% power, the inspector identified that the licensee had failed to establish an adequate procedure 12004-C, "Power Operation," Step 4.1.37, for placing AMSAC equipment in operation in that the procedure specified the equipment in service at 60% when the design basis specifies 40%. AMSAC equipment is required by 10 CFR 50.62 to automatically initiate the auxiliary feedwater system and initiate a turbine trip under conditions indicative of an anticipated transient without scram.

This is a Severity Level IV violation (Supplement I)

Pursuant to the provisions of 10 CFR 2.201, Georgia Power Company is hereby required to submit a written statement or explanation to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555, with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector, Vogtle, within 30 days of the date of the letter transmitting this Notice. This reply should be clearly marked as a "Reply to a Notice of Violation" and should include: (1) admission or denial of the violation, (2) the reason for the violation if admitted, (3) the corrective steps which have been taken and the results achieved, (4) the corrective steps which will be taken to avoid further violations, and (5) the date when full compliance will be achieved. Where good cause is shown, consideration will be given to extending the response time. If an adequate reply is not received within the time specified in this Notice, an order may be issued to show cause why the license should not be modified, suspended, or revoked or why such other action as may be proper should not be taken.

FOR THE NUCLEAR REGULATORY COMMISSION

Alan R Herdt

Alan R. Herdt, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Dated at Atlanta, Georgia
this 15 day of June 1989

Report Nos.: 50-424/89-14 and 50-425/89-15

Licensee: Georgia Power Company
P.O. Box 1295
Birmingham, AL 35201

Docket Nos.: 50-424 and 50-425 License Nos.: NPF-68 and NPF-81

Facility Name: Vogtle 1 and 2

Inspection Conducted: March 18 - May 5, 1989

Inspectors:
J. E. Rogge, Senior Resident Inspector — Date Signed
R. F. Aiello, Resident Inspector — 6-15-89 Date Signed
C. A. Patterson, Project Engineer (April 3-6) — 6-15-89 Date Signed
J. E. Menning, Hatch Senior Resident (April 1-2) — Date Signed
R. E. Prevatte, Summer Senior Resident (April 1-2) — Date Signed
P. C. Hopkins, Summer Resident (April 1-2) — Date Signed

Accompanied By: Rick McWhorter (March 27-30)

Approved By:
M. V. Sinkule, Section Chief
Division of Reactor Projects — 6-15-89 Date Signed

SUMMARY

Scope:

This routine inspection entailed resident inspection in the following areas: plant operations, radiological controls/chemistry, maintenance, surveillance, security, startup testing (Unit 2), engineering technical support, and quality programs and administrative controls affecting quality.

8906280135

Results:

In the areas inspected, fourteen violations were identified. Of these, one violation was cited, and thirteen violations were non-cited pursuant to the discretionary provisions of the NRC Enforcement Policy. The cited violation was identified in the area of operations, and it involved six examples of failure to establish or implement procedures. One of the six examples pertained to Unit 1 only (paragraph 5.f), three pertained to Unit 2 only (paragraphs 4.b(3)(q), 4.b(3)(r), and 4.b(3)(s)), and two pertain to both units (paragraphs 2.b(1) and 3). Of the thirteen non-cited violations, five pertained to Unit 1: one in the area of radiological controls/chemistry (paragraph 4.b(2)(d)), two in the area of surveillance (paragraphs 4.b(2)(a) and 4.b(2)(b)), and two in the area of emergency technical support (paragraphs 4.b(2)(c) and 4.b(3)(h)). The remaining eight non-cited violations pertained to Unit 2. Three were identified in the area of plant operations (paragraphs 4.b(2)(f), 4.b(3)(m), and 4.b(3)(p)), three were identified in the area of radiological controls/chemistry (paragraphs 4.b(2)(h), 4.b(2)(i), and 4.b(2)(j)), one was identified in the area of maintenance (paragraph 4.b(2)(k)), and one was identified in the area of engineering technical support (paragraph 4.b(2)(e)).

Two inspector followup items were also identified involving the adjustment of the P-9 setpoint when steam dumps are removed from service (paragraph 3) and the resolution of restoring the safety system monitor panel to a condition to correctly indicate the operability status (paragraph 5.d).

Two strengths and one weakness was noted within the report. The areas of maintenance and startup testing (Unit 2) were noted as strengths with the area of operations noted as a weakness.

- Maintenance (paragraph 2.b(7)) was considered a strength primarily due to the planning and execution of the work schedule. Short system outages on Unit 1 and short plant outages on Unit 2 were effectively conducted. Most noteworthy was the elimination of a 10-day scheduled outage during the Unit 2 test program due to this proficiency.

- Startup Testing on Unit 2 (paragraph 3) was a second strength even though one procedure error resulted in a preventable transient. The transient was preventable because the identical error was identified during Unit 1 test program. More significant was the proficient and efficient conduct of the Remote Shutdown Test and the Loss of Offsite Power Test.

- Operations evidenced weakness in the area of procedure establishment and implementation of the basic operating procedure 12004-C "Power Operation." Examples included in the cited violation are failure to open bypass isolation valves (paragraph 3), to secure from long-cycle cleanup (paragraphs 3 and 4.b(3)(s)), and to perform the transfer from auxiliary to main feedwater (paragraph 3). Other operations errors were noted in the LERs (paragraphs 4.b(2) and 4.b(3)). This concern has been verbally expressed to licensee management.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*G. Bockhold, Jr., General Manager Nuclear Plant
*A. L. Mosbaugh, Plant Support Manager
*R. M. Odom, Nuclear Safety & Compliance Manager/Plant Engineering Supervisor
*J. E. Swartzwelder, Manager Operations
W. F. Kitchens, Assistant General Manager Plant Operations
R. L. Legrand, Manager Chemistry and Health Physics
*H. M. Handfinger, Manager Maintenance
G. A. McCarley, ISEG Supervisor
*G. R. Frederick, SAER Supervisor
W. E. Mundy, Quality Assurance Audit Supervisor
C. L. Coursey, Maintenance Superintendent

Other licensee employees contacted included craftsmen, technicians, supervision, engineers, operations, maintenance, chemistry, quality control inspectors, and office personnel.

*Attended Exit Interview

An alphabetical list of acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Operational Safety Verification - (71707)(93702)(71715)

Unit 1 operated this inspection period in Power Operations (Mode 1) at 100% reactor power.

Unit 2 began this inspection period in Mode 4 (Hot shutdown). On March 18, 1989, Unit 2 entered into Mode 3 (Hot Standby). Later that same day (night shift), Unit 2 experienced an inadvertent SI due to personnel error followed by an NUE declaration. On March 19, following the SI, Unit 2 experienced a CVI due to 2RE-2565 radiation monitor. Additionally, on March 19, (night shift), Unit 2 experienced a FWI due to P-14 on SG #4 caused by personnel error. On March 28, Unit 2 entered Mode 2 (Startup), went critical, and commenced low power physics testing. On April 5, MFP "A" tripped resulting in a MDAFW pump actuation. On April 7, Unit 2 entered Mode 1. Later that same day, a FWI occurred as a result of a Hi Hi SG level. The unit later entered Mode 2. The unit reentered Mode 1 on April 8. On April 9, MFP "A" tripped resulting in a MDAFW pump actuation and subsequent Mode 2 entry. The unit reentered Mode 1 on April 10. The main turbine was tied to the grid on April 11. Later that same day, the reactor was tripped from the remote shutdown panel and placed in Mode 3 as part of a required test. While recovering, the unit received an AFW actuation during transfer of controls from remote shutdown panel with both MFW pumps tripped. On April 12, the unit entered Mode 2 and went critical with subsequent entry into Mode 1. On April 14, the unit conducted a LOSP test with subsequent entry into Mode 3. Following the LOSP test, the unit went into a three day maintenance outage. On April 15, the unit entered Mode 2, went critical, and entered Mode 1. On April 16, the unit was tied to the grid. On April 18, the main turbine was removed from the grid and tripped to conduct secondary system repairs. On April 19, the main turbine was returned to service and tied to the grid. On April 22, a unit turbine trip occurred due to a loss of stator cooling. This was followed by a FWI on SG #3 Hi Hi level and subsequent AFW start. The unit then entered Mode 2. Later the same day, the unit reentered Mode 1. On April 23, the main generator was tied to the grid. On April 24 with all of the 30% plateau testing complete, the unit commenced power ascension to 50% for 50% power plateau testing. On May 2, the unit was increasing power to 75% for 75% power plateau testing when a reactor trip occurred with the plant at 63% from a turbine trip following a test of the electrical overspeed trip circuit. On May 3, the unit reentered Mode 2, achieved Mode 1, and was operating at 75% at the end of the inspection period.

a. Control Room Activities

Control Room tours and observations were performed to verify that facility operations were being safely conducted within regulatory requirements. These inspections consisted of one or more of the following attributes as appropriate at the time of the inspection.

- Proper Control Room staffing
- Control Room access and operator behavior
- Adherence to approved procedures for activities in progress
- Adherence to technical specification limiting conditions for operation
- Observance of instruments and recorder traces of safety-related and important-to-safety systems for abnormalities
- Review of annunciators alarmed and action in progress to correct
- Control Board walkdowns
- Safety parameter display and the plant safety monitoring system operability status
- Discussions and interviews with the On-Shift Operations Supervisor, Shift Supervisor, Reactor Operators, and the Shift Technical Advisor (when stationed) to determine the plant status, plans, and to assess operator knowledge
- Review of the operator logs, unit logs and shift turnover sheets

No violations or deviations were identified.

b. Facility Activities

Facility tours and observations were performed to assess the effectiveness of the administrative controls established by direct observation of plant activities, interviews and discussions with licensee personnel, independent verification of safety system status and LCOs, licensee meetings and facility records. During these inspections, the following objectives were achieved:

(1) Safety System Status (71710) - Confirmation of system operability was obtained by verification that flowpath valve alignment, control and power supply alignments, component conditions, and support systems for the accessible portions of the ESF trains were proper. The inaccessible portions are confirmed as availability permits. An additional indepth inspection of the Unit 1 SI system was performed to review the system lineup procedure with the plant drawings and as-built configurations and to compare valve remote and local indications. Walkdowns were expanded to include hangers and supports and electrical equipment interiors. The inspector observed that the lineup was not in accordance with license requirements in that the SI RCDT pump discharge to RWST isolation (1-1204-U4-002), SI RWST INL FI-0928A and FI-0928B isolation valves were found open. DCs were properly issued by the SS to correct these deficiencies. These valve misalignments did not render the SI system inoperable. Several valves were noted to have missing label plates. Rooms A9 and A10 need a great deal of attention from a Health Physics and cleanliness point of view.

The licensee's program for maintaining control room drawings was reviewed. On April 28 and May 4, 1989, the unit control rooms and TSC drawings were inspected. This inspection included a detailed walkdown of the SI system (discussed above) and a review of the following drawings to determine legibility, current revision verification and verification that procedure valve lineups were appropriate:

1X4DB119 Rev 20	1X4DB130 Rev 22	1X4DB129 Rev 23
1X4DB133-1 Rev 23	1X4DB136 Rev 22	1X4DB161-1 Rev 22
1X4DB170-1 Rev 23	1X4DB120 Rev 14	1X4DB138-2 Rev 15
1X4DB136 Rev 22	1X4DB121 Rev 24	1X4DB131 Rev 19
1X4DB139 Rev 18	1X4DB138-1 Rev 16	1X4DB122 Rev 26
1X4DB132 Rev 14	1X4DB133-2 Rev 26	1X4DB135-1 Rev 21
1X4DB137 Rev 15	1X4DB161-2 Rev 22	1X4DB161-3 Rev 20
1X4DB170-2 Rev 22	1X4DB116-2 Rev 15	1X4DB117 Rev 18
1X4DB118 Rev 20	CX4DB173-557 Rev 1	CX4DB173-558 Rev 1
CX4DB173-553 Rev 1		

The inspector determined that the procedures for controlling the distribution of drawings were satisfactory. The drawings adequately represent the plant's current configuration. Three drawings 1X4DB133-1 Rev 23, 1X4DB122 Rev 24, and 1X4DB122 Rev. 26, (NSCW, SI, and RHR respectively) are too congested and therefore, difficult to read. It was also determined that most of the safety-related drawing ABNs were not legible. Three in particular which are examples of the worst case are 1X4DB161

Rev. 22, 1X4DB121 Rev. 24, and 1X4DB122 Rev. 26 (AFW, SI, and RHR respectively). Administrative procedure 00101-C, "Drawing Control," Step 3.4.4, requires that drawing legibility be ensured prior to distribution and engineering procedure 50009-C, "As-Built Notices," Step 4.6.3, requires ABNs to be legible and reproducible. This constitutes a violation of administrative procedure 00101-C and engineering procedure 50009-C.

This violation is one example of violation 50-424/89-14-01 and 50-425/89-15-01, "Failure To Implement Procedures 00101-C and 50009-C Resulting In TS 6.7.1.a Violation."

(2) Plant Housekeeping Conditions - Storage of material and components and cleanliness conditions of various areas throughout the facility were observed to determine whether safety and/or fire hazards existed.

(3) Fire Protection - Fire protection activities, staffing, and equipment were observed to verify that fire brigade staffing was appropriate and that fire alarms, extinguishing equipment, actuating controls, fire fighting equipment, emergency equipment, and fire barriers were operable.

(4) Radiation Protection - Radiation protection activities, staffing, and equipment were observed to verify proper program implementation. The inspection included review of the plant program effectiveness. Radiation work permits and personnel compliance were reviewed during the daily plant tours. Radiation Control Areas were observed to verify proper identification and implementation.

(5) Security - Security controls were observed to verify that security barriers were intact, guard forces were on duty, and access to the Protected Area was controlled in accordance with the facility security plan. Personnel were observed to verify proper display of badges and that personnel requiring escort were properly escorted. Personnel within Vital Areas were observed to ensure proper authorization for the area. Equipment operability or proper compensatory activities were verified on a periodic basis.

(6) Surveillance (61726)(61700) - Surveillance tests were observed to verify that approved procedures were being used, qualified personnel were conducting the tests, tests were adequate to verify equipment operability, calibrated equipment was utilized, and TS requirements were followed. The inspectors observed portions of the following surveillances and reviewed completed data against acceptance criteria:

Surveillance No.	Title
14000-1 Rev. 17	Operations Shift And Daily Surveillance Logs
14000-2 Rev. 2	Operations Shift And Daily Surveillance Logs
14220-1 Rev. 3	Main Turbine Valves Weekly Stroke Test
14228-2 Rev. 1	Operations Monthly Surveillance Logs
14230-1 Rev. 4	Weekly Train A & B Verification Offsite To Onsite Class 1E A.C. Distribution System Circuit Breaker Alignments While In Modes 1-4
14235-2 Rev. 1	Onsite Power Distribution Operability Verification
14450-2 Rev. 1	RCS Pressure Isolation Valve Leakage Test
14495-1 Rev. 3	TDAFW System Flow Path Verification
14551-2 Rev. 1	CCW Flow Path Verification
14808-2 Rev. 2	CCP And Check Valve Inservice Test
14825-2 Rev. 1	RCS Quarterly Inservice Valve Test
14905-1 Rev. 21	RCS Leakage Calculation

Surveillance procedure 14825-2 was conducted during the night shift on March 22, 1989. The resident inspector conducted a review of the data on the following morning. It was noted that data sheet 1 (test section 5.3.1) requiring independent verification was not documented for PORV block valves 2-HV-8000A and B. The inspector promptly brought this to the attention of the Operations Superintendent, OSOS, and unit SS. The SS took the necessary corrective action to complete these steps of the procedure on the following shift. It is apparent that an inadequate operator and supervisory review was conducted on the previous shift.

(7) Maintenance Activities (62703) - The inspector observed maintenance activities to verify that correct equipment clearances were in effect; work requests and fire prevention work permits, as required, were issued and being followed; quality control personnel were available for inspection activities as required; retesting and return of systems to service was prompt and correct; and TS requirements were being followed. Maintenance Work Order backlog was reviewed. Maintenance was observed and work packages were reviewed for the following maintenance activities:

MWO No.	Work Description
18901524	Replace NSCW Torque Switch Limiter Plate Due To Valve 1HV-1668A Not Stroking Properly
28902508	Stroke Steam Dump Valves
28902598	Main Feed Isolation Valve Repair

28902715	Investigate/Rework/Replace Cards As Required To Restore MFP Slave Relay K-620 To Proper Operation
28903135	Reset Power Range Detector Current Per Start Up Test Procedure 2-6SE-01 & 03

During this inspection, the inspectors noted that maintenance planning and execution was effectively conducted during short system outages (Unit 1) and plant outages (Unit 2). Most noteworthy was the elimination of a 10-day scheduled outage during the Unit 2 test program due to this proficiency.

One example of one violation was identified (paragraph 2.b(1)).

3. Startup Test Program Implementation/Verification - Unit 2 (72302)(72400B)(71715)

The inspector reviewed the present implementation of the Startup Test Program. Inspected Test Program attributes including review of administrative requirements, document control, documentation of major test events and deviations to procedures, operating practices, instrumentation calibrations, and correction of problems revealed by testing.

Periodic facility tours were made to observe Startup Test activities in progress. The inspector verified that procedural prerequisites and initial conditions were met. Verification was performed by the inspector's review of records (valve lineup sheets, test equipment calibration status, system status checklists, or appropriate sign-offs listed in procedure were maintained current) or by direct observation (monitoring instrumentation indications, valve positions, equipment position switches, or personnel actions). Discussions were held with responsible personnel, as they were available, to determine their knowledge of the Startup Test Program. Schedules for Startup Test Program completion and progress reports were routinely monitored. Specific inspections conducted are listed below:

Initial Criticality and Low Power Test Sequence

The initial criticality and low power test sequence directing the test activities as contained in procedure 2-600-04 was reviewed during testing. The following specific tests were partially witnessed:

(a) Step 6.2, Initial Criticality per Procedure 2-600-02
(b) Step 6.3, Determination of Low Power Physics Testing Power Range
(c) Step 6.4. Boron Endpoint, Isothermal Temperature Coefficient Measurement
(d) Step 6.4.11, Flux Map 2-6SE-02
(e) Step 6.11, Control Bank A Worth

Power Ascension Test Sequence (72509)(72582)(72583)

The power ascension test sequence directing the test activities as contained in procedure 2-600-13 was reviewed during testing. The following specific tests were partially witnessed.

(a) Step 6.1.1, Adjustment of Nuclear Instruments to 50% Trip Level
(b) Step 6.1.7, Main Feedpump Operation per 12004-C
(c) Step 6.1.8, Perform 12004-C
(d) Step 6.1.10, 2-6AB-01, Dynamic Auto Steam Dump Control
(e) Step 6.1.11, 2-6AE-01, Automatic Steam Generator Level Control Position Indication Test
(f) Step 6.1.20, 2-600-08, Remote Shutdown Test
(g) Step 6.1.23, 2-600-09, Loss of Offsite Power Test
(h) Step 6.4.5, 2-6SE-02, Flux Map At 30% Power
(i) Step 6.4.7, 2-6SE-03, Operational Alignment Of The Nuclear Instruments
(j) Step 6.5.3.1, 2-6SC-02, Load Swing Test
(k) Step 6.10.2, 2-6AE-01, Automatic Steam Generator Level Control
(l) 2-600-06, MFW Dynamic Response Test

On April 2, 1989, during performance of Step 6.1.8 which directed operation of the plant to proceed per procedure 12004-C, the inspector observed the unit perform the transfer from auxiliary feedwater to main feedwater for the #3 Steam Generator. Procedure 12004-C, Step 4.1.4, specifies that the transfer is to be completed as follows:

4.1.4 TRANSFER Auxiliary Feedwater to Main Feedwater one Steam Generator at a time by performing the following:

a. STABILIZE the SG NR level between 45% and 55%,
b. Slowly CLOSE the Auxiliary Feedwater Supply Valve and OPEN the BFRV while maintaining SG level in program band,
c. When the Auxiliary Feedwater Supply Valve is fully closed, Stabilize SG level and then PLACE the BFRV in automatic,
d. Repeat valve transfer for remaining Steam Generators,

Prior to the start of the transfer, the inspector noted that the Balance-of-Plant Operator discussed the transfer with the operator controlling Steam Generator level. The operators decided that the best way to make the transfer was for the BOP operator to close the Auxiliary Feedwater Supply Valve and the other operator would "punch" the BFRV into automatic. The operators then commenced the transfer without discussion with the Shift Supervisor. The BOP operator did however involve the shift supervisor in the transfer by directing him to display narrow range and wide range computer trends of #3 Steam Generator on the ERF computer. Upon closing the Auxiliary Feedwater Supply Valve, the SG Water level initially lowered. The second operator placed the BFRV into Automatic as previously planned. The BFRV automatic control began to slowly open in order to restore steam generator levels. The response time necessary for the controller and valve were slow and resulted in eventual overshoot of SG level to approximately 64%. The ERF computer displays were valuable in monitoring the inventory of water in the steam generator during the transient. A second effect was observed in the #1 SG involving lowering level. The #1 SG had been transferred to its BFRV on the prior shift. The BOP operator directed a plant equipment operator to fail the feedpump miniflow valve open. The inspector questioned the Operations Manager on why the procedure had not been followed for the transfer and why the miniflow valve had to be failed open. The inspector also noted that the prior Step 4.1.3g had been signed off complete when in fact, only the #1 and #3 BFIVs were open. Procedure 12004-C, Step 4.1.3.g, states:

4.1.3.g OPEN the Bypass Feed Isolation Valve and VERIFY the Feedwater Isolation Valve is closed for each SG.

The Operation Manager counseled the operators on not going in automatic control too soon. The failing of the miniflow valve was explained as a necessary evolution in that the flow from one feedpump feeding two steam generators is at the point when the miniflow valve closes (500 gpm) which affects the output pressure of the feedpump and hence flow to the steam generators. By failing the miniflow valve open the feedpump performs in a smoother manner. Later, the inspector learned that had all four BFIVs been open, that normal leakage through the BFRVs would account for about 500 gpm and the miniflow valve would have closed prior to or during the swapover on the first steam generator.

The fact that procedure 12004-C was not followed in Steps 4.1.3.g and 4.1.4 constitutes a violation of TS 6.1.7 requirements and is one example of violation 50-424/89-14-01 and 50-425/89-15-01, "Failure to Implement Procedure 12004-C, Steps 4.1.3.g and 4.1.4, For Performing Transfer From Auxiliary Feedwater To Main Feedwater."

The inspector observed the subsequent transfer to the #4 Steam Generator which proceeded in an orderly fashion except for the use of the ERF computer. When the Shift Supervisor called up the display, he obtained the #1 SG trend instead of the #4 SG. The transfer had already commenced and was essentially complete by the time the proper display was achieved. The following of procedure 12004-C, Step 4.1.4, by the operators resulted in a smooth transfer.

On April 3, 1989, during the performance of 2-6AB-01, "Dynamic Auto Steam Dump Control," the plant experienced a SG level transient when a test signal specified by procedure was incorrect. Procedure 2-6AB-01, Step 6.3.3, directed that a test signal be inserted equivalent to the signal generated at a T-ref of 553°F by using Attachment 10.5. Attachment 10.5 called for connection of a Ronan calibrator Model X85 (2.3 volt signal) (pins 26- and 27+). The reversal in polarity resulted in the steam dumps being commanded to full open when the controller was placed in the T-avg control mode per Procedure Step 6.3.5. At the time of the transient, six of the twelve dumps were isolated. The resultant swell in SG levels resulted in a feedwater isolation. Further details of the event is contained in LER 50-425/89-15. This same error occurred on Unit 1 during the startup program; however, an LER did not result. Unit 2 procedure development did not incorporate the Unit 1 procedure change. Failure to establish an appropriate procedure is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, and of TS 6.7.1.a.

This item is one of the examples of violation 50-424/89-14-01 and 50-425/89-15-01, "Failure To Establish An Adequate Procedure For The Testing Of Steam Dumps." (Refer to the discussion on LER 50-425/89-14 in paragraph 4.b(3)(r) for additional information.)

The inspector questioned why the identical error on Unit 1 did not result in a more severe transient. While no specific answers are known, speculation was made regarding the number of steam dumps that are inservice. On Unit 2 six of the twelve were inservice, and the test procedure called for verification that three valves be unisolated and ready for testing (PV-507A, B, and C). If Unit 1 had only three unisolated dumps, then the transient would not have resulted in as severe a level swell. A review by the inspector on procedure 12004-C noted that no guidance or control regarding steam dumps existed. Inspection of Unit 1 revealed that one steam dump was not inservice.

The above events regarding establishment and adherence to procedures was discussed with the General Manager on April 6, 1989. The inspector addressed observations regarding:

- failures to follow procedure 12004-C,
- failure of the Shift Supervisor to closely control the operator actions,
- failure to have appropriate procedures in place for control of steam dumps and feedwater pump miniflow valves,
- excessive eating of food in the control room, and
- telephone distractions to the operators.

In response to the above, the General Manager took action to address these concerns by having by operations manager review and discuss these events with operators and supervisors.

On April 7, 1989, a feedwater isolation occurred which illustrated another failure of the operators to implement procedure 12004-C. On April 6, with the unit in Mode 3 on long-cycle cleanup, the shift supervisor directed that in order to support another surveillance that long-cycle cleanup be secured from the control room. Following the surveillance, the cleanup was not restored. The following shift decided to replace the existing copy of 12004-C due to the number of items which had been signed off and however no longer represented the plant configuration. Since the action to secure long-cycle cleanup had been accomplished in the control room, the shift supervisor assumed that all of Step 4.1.3 directing the stopping of feedwater recirculation in long-cycle cleanup were not applicable. This error resulted in the failure of the plant to close six manual isolation valves and produced a situation wherein all four steam generators were cross connected. On April 7, with reactor power at approximatel 7%, operators noticed that the #1 SG BFRV was at 60% demand, #2 and #3 SGs were at % demand, and #4 SG was at 0% demand. Even though two steam generators gave the indication that only one BFRV was maintaining level, the operators notified I&C to investigate the indication problem. Since SGs 1 and 4 are on the same side of containment, the physical piping layout results in these two SGs being related. While resolving the problem, the operators decided to stroke the #2 MFIV as part of a maintenance functional test. As soon as the MFIV was opened, flow from the other SGs was diverted to the #2 SG until a feedwater isolation occurred due to Hi Hi #2 SG water level. The root cause is related to the first shift supervisor failing to implement procedure 12004-C, Step 4.1.3, in securing from long-cycle recirculation.

This item is an additional example of violation 50-424/89-14-01 and 50-425/89-15-01, "Failure To Implement Procedure 12004-C To Secure From Long-Cycle Recirculation." (Refer to the discussion of LER 50-425/89-15 in paragraph 4.b(3)(s) for additional information.)

The proper control of the steam dumps was addressed by the inspector as a concern in that the basis for the P-9 reactor protection interlock assumes that all dumps are available with normal pressurizer pressure control. TS 2.2.1, Table 2.2-1, item 18.d, specifies a trip setpoint of _ 50% where the reactor trip on turbine trip can be blocked. The inspector asked for a review by the licensee to determine if the actual setpoint should be adjusted downward when dumps were not available. Followup of this item will be tracked as IFI 50-424/89-14-02 and 50-425/89-15-02, "Review Licensee Evaluation Regarding Adjustment Of The P-9 Setpoint When Steam Dumps Are Removed From Service."

The above sections represent a weakness in the area of operations to implement and adhere to the basic "Power Operation" procedure 12004-C. It becomes apparent when combined with other operations procedure/implementation as documented in LERs 50-424/89-07, 50-425/89-02, 50-425/89-03, 50-425/89-04, 50-425/89-06, 50-425/89-08, 50-425/89-11, and 50-425/89-16 (see paragraph 4) that additional management attention and oversight are needed. Response by licensee management has been noted; however, effectiveness of this effort will require more time to evaluate.

The startup test program has been relatively successful with only one noted failure discussed above regarding the steam dump testing. More noteworthy was the proficient and efficient conduct of the Remote Shutdown Test and the Loss of Offsite Power Test. Key in the successful accomplishment was the decision by management to perform the test only during the day shift at specific times. This decision affected the appropriate personnel the ability to be well rested and prepared for the testing.

Three examples of one violation and one inspection followup item were identified.

4. Review of Licensee Reports (90712)(90713)(92700)

a. In-Office Review of Periodic and Special Reports

This inspection consisted of reviewing the below listed reports to determine whether the information reported by the licensee was technically adequate and consistent with the inspector knowledge of the material contained within the report. Selected material within the report was questioned randomly to verify accuracy and to provide a reasonable assurance that other NRC personnel have an appropriate document for their activities.

Monthly Operating Report - The inspector reviewed the Unit 1 and 2 monthly operating reports dated March 15, 1989. This review included the data revision for an earlier Unit 1 report. The inspector had no comments.

No violations or deviations were identified.

b. Licensee Event Reports and Deficiency Cards

Licensee Event Reports and Deficiency Cards were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events which were reported pursuant to 10 CFR 50.72, were reviewed as they occurred to determine if the technical specifications and other regulatory requirements were satisfied. In-office review of LERs may result in further followup to verify that the stated corrective actions have been completed or to identify violations in addition to those described in the LER. Each LER is reviewed for enforcement action in accordance with 10 CFR Part 2, Appendix C, and if the violation is not being cited, the criteria specified in Section V.G of the Enforcement Policy was satisfied. Review of DCs was performed to maintain a realtime status of deficiencies, determine regulatory compliance, follow the licensee corrective actions, and assist as a basis for closure of the LER when reviewed. Due to the numerous DCs processed only those DCs which result in enforcement action or further inspector followup with the licensee at the end of the inspection are listed below. The LERs and DCs denoted with an asterisk indicates that reactive inspection occurred at the time of the event prior to receipt of the written report.

(1) Deficiency Card Review

(a) DC 1-89-831, "Inadvertent Addition Of Radioactive Gas To Decay Tank Number 10."

On April 18, 1989, the licensee discovered that radioactive gas was apparently added to waste gas decay tank number 10 without the lab being notified for determining the quantity of gas contained in the tank. This deficiency will be followed up on when submitted as an LER.

(b) *DC 2-89-985, "Unit 2 Turbine Trip Following Standby Stator Cooling Pump Trip."

On April 22, 1989, a turbine trip occurred as a result of a loss of stator cooling during a routine swapping of stator cooling pumps. When the standby pump was started, both pumps tripped, causing the turbine to trip. While attempting to stabilize the plant, a feedwater isolation occurred due to Hi-Hi SG level on SG #3, leading to an AFW actuation when the running MFP tripped. The reactor was stabilized at 2% with the SG being fed from AFW. This deficiency will be followed up when submitted as an LER.

(c) DC 2-89-1027 "Reactor Trip From 60% Power On A Turbine Trip."

On May 2, 1989, the unit received a reactor trip from 60% power on a turbine trip. AFW actuated on Lo Lo SG level following the trip. All systems functioned as required. The turbine trip occurred while Engineering and a GE Vendor representative were investigating a test malfunction alarm which was received during the weekly turbine trip device operability test. The cause of the turbine trip is still under investigation. This deficiency will be followed up when submitted as an LER.

(2) The following LERs were reviewed and are ready for closure pending verification that the licensee's stated corrective actions have been completed.

(a) 50-424/89-06, Rev. 0, "Inadequate Functional Test Leads To Improper Termination Of Limiting Condition For Operation."

On January 30, 1989, the Gaseous Waste Processing System's Outlet Analyzer, 1ARC-1119, failed to pass the surveillance requirements of Technical Specification 4.3.3.10. The TS required grab samples to be taken and analyzed at least once per 24 hours. A micro fuel cell in the analyzer was replaced and tested on February 7, 1989. On February 23, 1989, a review of the work order discovered that the equipment was placed in service, even though a complete surveillance test of the analyzer had not been performed to verify that the surveillance requirements were met. The surveillance test was then performed satisfactorily. This event was caused by personnel error. Procedural inadequacies contributed to this event. The appropriate procedure was revised. The appropriate personnel have been counseled. Proper checks now exist to ensure all required testing is performed prior to exiting a LCO. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-424/89-14-03, "Failure To Perform Required Testing Per Surveillance Requirements Results In TS 4.3.3.10 Violations - LER 50-424/89-06."

(b) 50-424/89-07, Rev. 0, "Failure To Take Required Temperatures Results In Inadequately Performed Surveillance."

On February 16, 1989, while performing Procedure 14001-1, "Shift Area Temperature Log," the plant operator noted that there was no entry for Fuel Handling Building Room B008 for the two previous shifts. The Shift Supervisor was notified of the missed readings, which are required per Technical Specification 3.7.10. The current temperature was taken for Room B008 (76°F), and as it was well within the normal maximum technical specification limit (104°F), no compensatory action was required. The cause of this event was personnel error. Two plant operators failed to take the required reading and their respective shift supervisors failed to note the missing temperatures when the data sheets were reviewed. Corrective actions included counseling of the operators and shift supervisors on the importance of ensuring that all required technical specification surveillance temperatures are obtained and data sheets thoroughly reviewed. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-424/89-14-04, "Failure To Take Required Temperatures Results In Inadequately Performed Surveillance Resulting In A TS Violation - LER 50-424/89-07."

(c) 50-424/89-08, Rev. 0, "Inadequate Review Of Drawing Change Results In Use Of Improper Breakers."

On February 23, 1989, it was discovered that 125V DC breakers for motor-operated valves in the Turbine Driven Auxiliary Feedwater pump system were not the proper size. The breakers, as installed and as shown on design drawings, were 15 amp thermal magnetic but should have been sized as 30 amp thermal magnetic per the design criteria. Therefore, the plant has operated in a condition prohibited by Technical Specifications. Technical Specification 3.7.1.2 requires at least three independent steam generator auxiliary feedwater pumps and flowpaths to be operable. The undersized breakers were discovered as a result of an investigation of the same problem in Unit 2.

LCO 1-89-121 was entered. The breakers were replaced, successfully tested, and the LCO was exited. The cause of this event was due to inadequate review by the responsible engineer when a drawing change notice corrected the MOV horsepower rating form 0.66 hp to 1.0 hp. Corrective actions included a review of all 125V DC MOV breaker protection. This review indicated this incident to be an isolated case. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-424/89-14-05, "Failure To Conduct An Adequate Engineering Review Of The AFW Electrical System Which Led To AFW Inoperability Resulting In a TS 3.7.1.2 Violation - LER 50-424/89-08."

(d) 50-424/89-10, Rev. 0, "Valved Out Radiation Monitor Leads To Unmonitored Liquid Waste Release."

On March 14, 1989, a plant operator was preparing to perform a liquid waste release per procedure 13216-1, "Liquid Waste Release." The operator verified that radiation monitor 1-RE-0018 was registering normal background levels and that isolation release valve 1-RE-0018 would close on a high radiation signal. The release began and the operator checked the signal from 1-RE-0018 and found it was not registering above background levels. A brief search found that the inlet valve to 1-RE-0018 was closed. This valve, 1-1901-X4-144, was opened; 1-RE-0018 registered the proper activity level; and the liquid waste release continued. The release was completed and the closure of the inlet valve resulted in liquid waste being released unmonitored which is a condition prohibited by Technical Specification 3.3.3.9. The operator omitted the performance of a pre-release line flush which would have ensured that the inlet valve was opened. Corrective actions included counseling the operator and changing procedure 13216-1 to require independent verification of the inlet valve being open. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-424/89-14-06, "Failure To Follow Procedures While Conducting A Liquid Waste Release Resulting In A TS 3.3.3.9 Violation - LER 50-424/89-10."

(e) 50-425/89-05, Rev. 0, "Inadequate Review Of A Modification Results In A Technical Specification Violation."

On March 17, 1989, while investigating a problem with the Automatic Surveillance Technical system, field voltage measurements were taken that revealed an electrical short on valve 2HV-19051, the Reactor Coolant Pump #1 thermal barrier isolation valve. The valve was required to be operable upon entry into Mode 4, which had occurred on March 4. A Surveillance had been performed on February 4, 1989, to prove operability of 2HV-19051; however, a change to the ASTEC system wiring on February 10 resulted in valve 2HV-19051 being inoperable. The cause of this event was the issuance of an incorrect As-Built Notice. Corrective actions included counseling the appropriate engineering personnel involved, training for all engineering personnel recently transferred from the Unit 2 test organization on use of the ABN, and issuing a second ABN to restore the system to its original configuration. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-04, "Failure To Meet A Mode Change Prerequisite Resulting In A TS 3.7.12 Violation Requiring Valve 2HV-19051 To Be Operable Prior To Entering Mode 4 - LER 50-425/89-05."

(f) *50-425/89-06, Rev. 0, "Operation Of Incorrect Handswitch Results In Safety Injection."

On March 18, 1989, while warming main steam lines as part of procedure 12002-2, "Unit Heatup To Normal Operating Temperature And Pressure," automatic Engineered Safety Features actuation. A step of the procedure called for handswitches HS 40047/48 to be operated to reset the main steam isolation signal. However, handswitches HS 40068/69 were operated. These switches reset the low steamline pressure safety injection and steamline isolation logic, removing the blocking signal. Since the main steam line pressure was below the safety injection setpoint pressure, the SI occurred. Appropriate ECCS pumps and valves actuated resulting in approximately 2900 gallons being injected into the Reactor Coolant System. The SI was manually reset and injection into the RCS was terminated. The cause of this event was personnel error. The operator failed to ensure that the proper switch was being operated. Corrective actions will include counseling the operator on the importance of verifying that the proper device is being operated, changing the color of SI handswitches, adding cautions to the handswitches, and incorporating details of this event into training. This item was formally discussed following the Enforcement Conference on March 22, 1989. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-05, "Failure To Follow Procedures Resulting In Inadvertent SI Actuation - LER 50-425/89-06."

(g) 50-425/89-07, Rev. 0, "Lockup Of A Computer Communications Device Results In Containment Ventilation Isolation."

On March 19, 1989, while restoring the Plant Effluent Radiation Monitoring System to service the plant experienced an automatic Engineered Safety Features actuation which resulted in a Containment Ventilation Isolation. Appropriate valves and dampers actuated to isolate containment ventilation. Control room operators verified that no abnormal radiological conditions existed using 2RE-0002/0003. The monitor that actuated the CVI, 2RE-2565, was placed in bypass. The CVI was reset and equipment that actuated was returned to normal operating position. Due to an earlier SI, power was lost to most of the PERMS system. On restoration of power, the computer parameter files are initialized with a -9.99E-20 value. The computer replaces this value with parameters received from each monitor. Due to a communication failure of a multiplexer, communication with the monitors was lost and no value was received for 2RE-2565. When the mutiplexer was reset the computer detected the original power failure for 2RE-2565. On a power failure, the computer gives the monitor the current parameter on file and assigned the monitor -9.99E-20 value. This resulted in a high alarm, causing the CVI actuation. Corrective action is a procedure revision to require 2RE-2565 to be placed in bypass when the computer is initialized to receive parameters.

(h) 50-425/89-09, Rev. 0, "Procedure Misinterpretation Leads To Late Surveillance Testing."

On March 20, 1989, a diesel fuel oil shipment arrived onsite for offloading into the Diesel Fuel Oil Storage tanks. A technician obtained and analyzed a sample. The technician and his foreman interpreted a note in the analyses scheduling procedure to mean that the neutralization number and mercaptan were not required to be performed. In fact, only the mercaptan was exempt from the analysis and neutralization number was required to be performed. After the analysis found the other fuel properties to be satisfactory, the shipment was unloaded into the DFOS tanks. Meanwhile, a second diesel fuel oil shipment arrived onsite, a sample was obtained and analyzed as before and unloading into the DFOS tanks began. A laboratory supervisor reviewed the data sheets and question the omission of the neutralization number from the data sheets. After the requirement was clarified, the technician obtained the original samples from each shipment and determined that the neutralization number of each was within technical specification requirements. The cause of this event was the misleading nature of the procedure note. The procedure note was rewritten and clarified. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-06, "Failure To Establish An Adequate Sampling Procedure For Diesel Fuel Oil Per TS 6.7.1.a - LER 50-425/89-09."

(i) 50-425/89-10, Rev. 0, "Radioactive Discharge Without Permit Leads To Technical Specification Violation."

Technical Specification 3/4.11.1 requires that releases of radioactive materials to unrestricted areas be sampled and analyzed for appropriate alpha, beta, and gamma emitters. On March 8, 1989, the contents of the Unit 2 Turbine building drain tank, 2-2412-T4-002, were sampled for gamma emitters to determine if a release permit was required. On March 9, a plant operator released the tank contents to the Unit 2 Waste Water Retention Basin without a permit. On March 14, during a review of releases, it was found that no permit had been issued for the March 9, release. The permit ensures that required samples have been taken, analyzed and are within allowable limits for releases. Procedure 13211-2, "Turbine Building Drain System," required that sample analysis be used to determine how drain tank contents are to be processed but did not specify that a release permit may be required. The cause of this event was that the operator did not obtain a radioactive release permit prior to releasing. Procedure 13211-2 has been revised to provide specific instructions that a radioactive release permit may be required for releasing the contents of a turbine building drain tank. Also, at shift briefings, operators were reminded that waste permits are required prior to release of radioactively contaminated tank contents. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-07, "Failure To Obtain A Radioactive Release Permit Prior To Releasing Radioactive Materials To

Unrestricted Areas Resulting In A TS 3/4.11.1 Violation - LER 50-425/89-10."

(j) 50-425/89-12, Rev. 0 "Operating Incorrect Switch Results In Inoperable Monitor Requiring Entry Into TS 3.0.3."

On March 30, 1989, while performing maintenance on 2RE-2562A, an Instrument and Controls Technical inadvertently placed 2RE-2562A and 2RE-2562C in purge instead of activating the paper drive on 2RE-2562A. This caused 2RE-2562C to be inoperable. Later the same day, a chemistry foreman discovered 2RE-2562C to be inoperable and notified the control room. An entry into TS 3.0.3 was made due to an existing limiting condition for operation for the Reactor Coolant System Leakage Detection System and 2RE-2562C being inoperable. With 2RE-2562C inoperable the LCO for Technical Specification 3.4.6.1 could not be met.

2RE-2562C was restored to service and TS 3.0.3 exited. The cause of this event was personnel error. The I&C technician failed to pay attention to detail when activating plant equipment. The purge switch was activated instead of the paper drive. Corrective actions included counseling the individual and issuing a memo to all I&C personnel concerning attention to detail when performing maintenance/trouble shooting on plant equipment. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-08, "Failure To Follow Procedures While Performing Maintenance On 2RE-2562A Resulting In The Plant Operating In A Condition Prohibited By TS Thus Requiring Entry Into TS 3.0.3 - LER 50-425/89-12."

(k) 50-425/89-13, Rev. 0, "Flood Barrier Removal Leads To Auxiliary Feedwater Inoperability."

Technical Specification 3.7.1.2 requires that three independent steam generator AFW pumps and associated flow paths be operable in Modes 1, 2, and 3. On March 30, 1989, plant personnel were conducting a routine walkdown. They found a flood protection barrier removed from the wall between the AFW discharge piping room (room 105) and the Turbine Driven AFW pump room (room 106). The barrier was replaced and the TS action statement was exited. The cause of this event is an apparent personnel error by removing the barrier without the proper review and approval. Work had been performed on a check valve in room 105. When a functional test was performed on March 23, the existence of a flood barrier and precautions to be observed were not addressed by those requesting the test or by those implementing the work order. A sign will be installed near the flood barrier and information will be added to the equipment file advising of the flood barrier's existence. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-09, "Failure To Maintain The Auxiliary Feedwater System Operable Resulting In A Condition Prohibited By TS 3.7.1.2. - LER 50-425/89-12."

(1) *50-425/89-16, Rev. 0, "Unplanned Auxiliary Feedwater Actuation On Recovery From Remote Shutdown Test."

On April 11, 1989, while recovering from a Remote Shutdown Test, an automatic Engineered Safety Features actuation (auto start signal to motor driven Auxiliary Feedwater pumps) occurred. During the Remote Shutdown test, both Main Feedwater Pumps were manually tripped and AFW was in service. With both MFPs tripped an AFW actuation signal was generated; however, while control was at the Remote Shutdown Panel, the signal is interrupted. When control was returned to the control room, the signal was reinstated. As the AFW pumps were already in operation, the AFW actuation signal caused the discharge valves of the Train A to stroke full open. Control room operators immediately throttled AFW flow to prevent overfilling of the steam generators. MFP "A" was reset to allow return of the remaining trains to the control room. All AFW systems were restored to readiness. The cause of this event was a situation that was not anticipated by the procedure. Procedure 18038-2, "Operation From Remote Shutdown Panels," will be revised to caution operators of a possible actuation of transfer of control to the control room.

(3) The following LERs were reviewed and closed.

(a) 50-424/87-81, Rev. 0, "Excessive Valve Weight Could Have Prevented Fulfillment Of Safety System Function."

On May 5, 1987, two valves supplied by Anchor Darling Valve on the sludge mixing recirculation line of the Refueling Water Storage Tank were found to weigh significantly more than shown on the A/DV drawings. The initial analysis from an employee of Bechtel Power Corporation indicated that the valves weighed in excess of the seismic design capacity of their associated pipe supports and that if a line failure had occurred in the non-safety related portion of the sludge mixing line during a seismic event, the valves could have been closed and allowed the RWST water volume to be available for plant shutdown. On March 6, 1989, the Project Field Engineering-Office advised plant personnel that there was an error in the application of potential failure point and that the potential failure point was actually between the valves and the RWST. Thus, if a seismic event caused line failure to occur, the broken line could have potentially drained the RWST to a level below minimum requirements for plant shutdown. The cause of this condition was determined to be the failure of A/DV to advise Bechtel of a change in valve weights from those originally shown on the valve drawings and an error by a Bechtel Power employee in the initial review of this condition. Corrective actions included adding an additional pipe support and reviewing other safety related valves for weight discrepancies. The inspector has no further questions.

(b) *50-424/88-16, Rev. 0, "Water Leakage Into Control Room/Potential Exists For A Safety System Failure."

On June 3, 1988, smoke from an electric duct heater actuated smoke detection alarms. Although sprinkler heads did not actuate, water from the preaction valve leakoff lines ran into the upper cable spreading room and seeped into the control room from the ceiling. Water entered some process panels and led to spurious equipment actuations in the Reactor Coolant System which were promptly addressed and corrected by control room personnel. On June 5, 1988, it was concluded that a condition existed which alone could have prevented the fulfillment of the safety function of a system needed to mitigate the consequences of an accident. The cause of this event is an inadequate design of the control room ceiling penetrations which are supposed to be watertight. Corrective actions were verified complete. This item resulted in a NRC violation 50-424/88-24-01.

(c) 50-424/88-19, Rev. 0, "Inadequate Installation Leads To Containment Ventilation Isolations."

On June 10, 1988, a CVI occurred due to an apparent power supply failure in radiation monitor 1RE-2565C. The appropriate dampers and valves actuated as designed. Control room personnel verified that no abnormal condition existed. 1RE-2565C was bypassed and the CVI signal was reset. Later, the same day, another CVI occurred, when plant personnel removed 1RE-2565C from bypass in order to reenter monitor setpoints. Again the proper dampers and valves actuated and control room personnel verified that no abnormal radiation condition existed. 1RE-2565C was again placed in bypass and the CVI signal was reset. An investigation demonstrated that the cause of the CVI was an inadequate installation which left a flow transmitter shield wire exposed that electrically grounded, simulating a loss of power. Corrective action included insulating the shield wire and new default values were installed.

(d) 50-424/88-20, Rev. 1, "Inadequate Breaker Leads To Condition Prohibited By Technical Specification."

On June 29, 1988, it was determined that ten containment penetrations may not have adequate redundant overload protection, as required by Regulatory Guide 1.63. The redundant protection was not provided because in each of the ten penetration circuits one of the two breakers used was magnetic-only, which did not provide adequate overload protection for the penetration. The other breaker provided was a thermal-magnetic and provided adequate overload protection for the penetration. Since the magnetic-only breakers did not provide the redundant overload protection, the requirements of Technical Specification 3.8.4.1 for operability was not satisfied. When it was determined that redundant overload protection may not have been adequate over the entire range, the identified containment penetrations were declared inoperable and the requirements of Technical Specification 3.8.4.1 were satisfied while the breakers were being replaced. Prior to the operation of Vogtle Unit 1, a construction test was performed for each breaker to verify its tripping function. All tests were performed satisfactorily and the breakers declared operable. The inspector has reviewed documentation which indicated that the corrective action was complete. The magnetic-only breakers were replaced with thermal-magnetic breakers.

(e) *50-424/88-22, Rev. 1, "Failed Potential Transformer Leads To Turbine/Reactor Trip."

On July 14, 1988, a generator/turbine/reactor trip occurred as a result of an overexcitation condition on the generator field. Control rods inserted. The Main Feedwater system isolated and the Auxiliary Feedwater system actuated. Control room operators responded properly to assist in plant stabilization. An investigation revealed that the failure of a potential transformer caused the primary fuse to blow. The resultant transient caused the GENERREX voltage regulator to malfunction, increasing generator voltage to the Volts/Hertz relay setpoint, which subsequently initiated a generator/turbine/reactor trip. Corrective action includes replacing all primary PT fuses, PT 2A, and the malfunctioning circuit boards in the GENERREX system. The GENERREX system's operational history has been evaluated and additional adjustments are not considered necessary at this time. Engineering review of design enhancements to the present GENERREX system will continue to be performed as part of the Trip Reduction Program. The failed PT was analyzed and a winding failure was identified. Improved test methods to detect this type of PT failure were evaluated. However, a more appropriate test method has not been identified. This LER was closed in report 50-424/88-37.

(f) 50-424/88-23, Rev. 0, "Inadequate Design Leads To Condition Prohibited By Technical Specification."

On July 29, 1988, LER 50-424/88-20 was issued, identifying that several electrical penetrations may not have been provided with adequate redundant overload protection. As a result of the interpretation for reportability of that event, two previously identified deficiencies have been re-evaluated for reportability. As a result of the re-evaluation, an event that was discovered on August 14, 1987, was determined to be reportable on July 28, 1988. The other event was discovered on July 7, 1987, and determined to be reportable on August 11, 1988. It was determined that for each event, redundant overload protection may not have been adequate for the entire range of protection as required by Regulatory Guide 1.63. Technical Specification 3.8.4.1 required that electrical penetration overload protection may not have been provided for several penetrations, Unit 1 may have been operating in a condition prohibited by TS until the event was discovered. For each event the limiting condition for operation action statement for TS 3.8.4.1 was implemented on the event discovery dates of July 7, 1987, and August 14, 1987. The event on August 14, 1987, involved electrical penetrations No. 12 and No. 69, concerning the #12 and #14 size conductors. The other event on July 7, 1987 involved penetration No. 03, 14, 34, 41, 60, and 61, concerning 6.0 size conductors. The inadequate overload protection was discovered during a broadness review for Unit 2 by the designer, Bechtel Power Corporation. The inspector verified the work complete by reviewing the closed MWOs.

(g) 50-424/88-26, Rev. 0, "Use Of Improper Tools Leads To Containment Ventilation Isolation."

On September 7, 1988, an electrician was in the process of installing shorting bars into fuse holders following the completion of an electrical switch replacement. The electrician unintentionally created a short between two 120 volts AC circuits. Various alarms and indicators actuated, including those for a CVI. The appropriate CVI valves and dampers actuated. Control room personnel verified that no abnormal radiation condition existed by observing redundant monitors. The control room personnel and the electrician immediately confirmed that the electrical short had initiated the CVI. The cause of this event was the use of an improper tool by the electrician. Fuse pullers provided to the electrician would not fit between the inserted shorting bars, so he used needle-nose pliers to perform the insertions. These pliers made the electrical short by simultaneously contacting two shorting bars following one shorting bar's insertion. Appropriate personnel were advised to avoid the use of needle-nose pliers or makeshift tools for installation of fuses or shorting bars. The proper size fuse-pullers were made available.

(h) 50-424/88-30, Rev. 0, "Surveillance Missed Due To Inoperable Rod Position Deviation Monitor."

On October 27, 1988, while preparing a licensing document change, it was discovered that a plant computer design feature for monitoring deviations between Digital Rod Position Indication System and Demand Position Indication System had not been implemented within the plant computer software as intended. The absence of this feature means the Rod Position Deviation Monitor is operable for this function and that surveillance 4.1.3.2 has not been met, when required, since issuance of the Unit 1 license. The surveillance required operability determination of the digital rod position indicators. For this determination, the DPIS must be verified to be with + or - 12 steps of the DRPIS every 12 hours, except when the RPDM is inoperable, then the requirement is at least once per 4 hours. As the plant staff were unaware of the software omission, they did not take the required action to manually make the comparisons every 4 hours as required. The cause of this event was the omission of appropriate rod supervision programs in the original vendor supplied computer software specifications. Corrective actions include increased frequency of the surveillance and an evaluation to determine if either changes to the computer software are feasible or changes to licensing documents are required. The inspector reviewed documentation which indicated that the corrective action was complete. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-424/89-14-07, "Failure To Conduct Surveillance Resulting In A Violation Of TS 4.1.3.2 - LER 50-424/88-30."

(i) *50-424/88-41, Rev. 0 and 1, "Containment Purge Supply Isolation Valve Inoperable Due To Failure To Fully Close."

On December 13, 1988, while performing a revised Type C Local Leak Rate Test for surveillance of the containment purge supply isolation valves in Penetration 83, it was discovered that the 24-inch containment purge supply isolation valve 1-HV-2626A was not fully seated. This condition is prohibited by Technical Specification 3.6.1.7 which requires that this valve be closed and sealed closed. LCO 1-88-922 was entered for 1-HV-2626A failing the leak rate test. This event occurred because the valve did not fully close, even though the limit switch indicated that the valve was closed. Corrective actions included issuing LCO 1-88-922, immediate manual seating of the valve and successfully repeating the LLRT, and establishing conservative administrative controls to ensure that each 24-inch purge isolation valve, if cycled, will be either manually seated or have an LLRT performed, as appropriate.

Procedures 13125-1, Rev. 8, and 13125-2, Rev. 2, were verified by the inspector to have been revised.

(j) *50-424/89-05, Rev. 0, "Trip Of Main Feed Pump On High Vibration Resulting In Manual Reactor Shutdown."

On February 10, 1989, Control Room operators received Main Feedwater Pump Turbine "A" high vibration alarms. A check of the vibration monitor system showed a vibration of only 1.2 mils. (The vibration system alarms at 3 mils and trips at 5 mils). Shortly thereafter, MFP "A" tripped. Steam/feedwater flow mismatch alarms were received on all four steam generators. Turbine load was manually reduced to approximately 700 MWe and control rods placed in Auto to follow load Steam dump valve controllers were manually operated to attempt to match steam/feed flow. SG #4 reached 20% level and the Shift Supervisor directed the reactor to be manually tripped. Feedwater isolation and start of Auxiliary Feedwater pumps occurred as expected. However, the Turbine Driven AFW pump tripped on overspeed after starting. The cause of the MFP high vibration trip was not positively identified. The cause of the TDAFW pump overspeed trip, although not positively identified, may have been caused by particulate contamination of the lube oil, which serves as the control system hydraulic fluid. Corrective actions included temporarily installing vibration instrumentation to collect MFP vibration data. Additional surveillances were also performed on the TDAFW pump to ensure operability.

(k) 50-424/89-09, Rev. 0, "False Radiation Monitor Signal Caused Containment Ventilation Isolation And TS 3.0.3 Entry."

On March 13, 1989, radiation monitor 1RE-0003 spiked high causing a Containment Ventilation Isolation. Appropriate valves and dampers actuated from the CVI signal to isolate containment ventilation. LCO 1-89-155 was entered for 1RE-0003. Radiation monitor 1RE-0002 was out of service for a surveillance and 1RE-2565 was not operable because of reliability concerns. Technical Specification 3.3.2, Table 3.3-2, requires a minimum of two of the three channel be operable, but there is a provision for operation with only one channel in operation. An entry was made into TS 3.0.3 since all three channels were inoperable. Control room operators verified that no abnormal radiological conditions existed using 1RE-0002, which was functional but not operable. Later that same day, 1RE-0002 was declared operable, the high alarm on 1RE-0003 was cleared, the monitor placed in bypass, and the CVI signal was reset. The cause of this event was the failure of the detector tube. The tube was replaced; however, the replacement tube did not function properly and required replacement due to degradation of the voltage plateau. The replacement tube was monitored and the monitor was declared operable.

(l) 50-425/89-01, Rev. 0, "Spurious Signal Resulting From Circuit Board Causes Control Room Isolation."

On February 14, 1989, a Control Room Isolation occurred due to a spurious signal from radiation monitor channel 2RE-12116. Prior to this actuation, the Safety Parameters Display Console had received intermittent trouble light indications from the channel. Control room operators verified no high radiation condition existed. The monitor's output was blocked, a LCO was entered, the CRI signal was reset, and normal ventilation was established. Radiation monitor channel 2RE-12116 was returned to service and the LCO exited on February 18. The event was caused by a random failure detected on the Central Processing Unit board in the Digital Processing Module. This random event caused the internal timer to lock up and initiate a system reset signal. During a system reset, the monitor's fail safe function initiates a high alarm signal which caused the CRI actuation. Corrective actions included initiation of a LCO for the monitor, replacement of the defective circuit board, observation of the monitor for proper operation and return of the monitor to service.

(m) *50-425/89-02, Rev.0 "Opening Discharge Valves Causes Plant Operation Outside Of Technical Specifications."

Technical Specification Section 3.4.1.4.2 states," ...Reactor Makeup Water Storage Tank discharge valves (1208-U4-175, 1208-U4-176, 1208-U4-177, and 1208-U4-183) shall be closed and secured in position (in) Mode 5 with reactor coolant loops not filled." On February 19, 1989, the unit made its initial entry into Mode 5, valves 2-1208-U4-175 and 2-1208-U4-177 were opened. After shift change, new shift personnel realized that the reactor coolant system loops were not filled and that the two open discharge valves were required to be closed. A LCO was initiated, the valves were closed and locked, and the LCO was terminated. Plant personnel believed that filling the RCS above the loops to the reactor vessel flange level constituted a "loops filled" condition, after which opening the discharge valves would have been permissible. With the discharge valves open, an inadvertent dilution event of the RCS could have been initiated. A TS interpretation of what constitutes "loops filled" has been added to the Operations Required Reading Book. The personnel involved were counseled regarding the importance of complying with TS. Inspector followup determined that prior to the Mode 5 entry, the SS had been asked to open these same valves to allow chemistry to add primary chemicals. At that time, the SS was aware that TS 3.9.1 required the valves to be maintained shut in Mode 6 and thought that the change to Mode 5 would allow the evolution. TS 3.4.1.4.2 however, also controls these valves when the RCS loops are not filled. Operations procedure 12006-C established positive control of these valves by tagging them closed. These valves are untagged by operations procedure 13000-2 upon filling and completing air sweeping of the RCS. The removal of the RMWST valves to the CVCS was a discussion item at the shift turnover, however, neither SS recognized the consequences. Later in the shift, the deficiency was identified and corrected. This item was formally discussed following the enforcement conference on March 22, 1989. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-10, "Failure To Maintain RMWST, Discharge Valves Shut Closed And Secured In Position While In Mode 5 Resulting In TS 3.4.1.4.2 Violation - LER 50-425/89-02."

(n) 50-425/89-03, Rev. 0, "Depressurizing RHR System Leads To Technical Specification 3.0.3 Entry."

On March 9, 1989, with the unit having just entered mode 3 for the initial heatup, preparations were being made to perform the Pressure Isolation Valve Leakage Test. In order to ensure proper pressure across the valves to be tested, the Shift Supervisor decided, without an approved procedure, to depressurize the Residual Heat Removal system, using the RHR test return valves. The SS directed a momentary opening of these valves. This resulted in the return line valves being left open for approximately 14 hours, reducing the flow capacity of both RHR trains, and leading to operation under Technical Specification 3.0.3 provisions. This event was caused by (1) operations personnel attempting an evolution without approved procedural guidance, (2) lack of closed loop communication, and (3) inadequate system status sensitivity by the operations shift team. Corrective actions include (1) counseling the Shift Supervisor and briefing of each operating crew by th Plant General manager on the importance of conducting plant evolutions with approved procedures, (2) changing the appropriate procedure, (3) stressing precise control room communications, (4) stressing sensitivity to system status in shift briefings and requalification training, and (5) improving the locked valve program. This item was cited as a NRC violation in report 50-425/89-12. Remaining corrective actions will be verified in closeout of the violation.

(o) *50-425/89-04, Rev. 0, "Reactor Coolant System Leakage During Check Valve Testing."

On March 9, 1989, with Unit 2 in Mode 3, plant operations personnel performed a pressure isolation valve leakage test. The Primary Coolant Loop #3 Cold Leg Check Valve (2-1204-U6-085) exhibited excessive leakage. A Notification of Unusual Event was declared, because the Reactor Coolant System leakage exceeded the technical specification limit of 5 gpm specified in Section 3.4.6.2.f. On March 10, 1989, the plant entered Mode 5 and the NUE was terminated. The event was caused by excessive wear on internal check valve components. Wear was found near the pivot pin which allowed the disc to drop down and not seat properly. The valve consists of a disc with two arms which insert into a lock block. The pivot pin goes into the lock block. The disc arms are notched out for alignment with the pivot pin. Wear was found on both notches in the arms which allowed the disc to drop. Corrective action included replacement of the internal components in this valve and the three identical check valves in the other three loops.

(p) *50-425/89-08, Rev. 0, "Improper Control Of Steam Generator Water Level Leads To Feedwater Isolation."

On March 19, 1989, unit 2 heatup was in progress. The unit Balance-of-Plant operator was manually controlling the steam generators water levels when a technician requested his assistance in performing a surveillance test. The BOP operator left the front panel to go to a back panel area. When he returned several minutes later, he found that an automatic feedwater isolation had occurred because SG #4 had exceeded the 78% (narrow range) high-high water level setpoint. The operator stopped the feed to SG #4, returned the flow to normal, and long cycle recirculation was re-established. The BOP operator intended to leave the front panel for only a few moments and did not request relief. This is the direct cause of this event. Contributing to this event was the Shift Supervisor's omission in assigning a dedicated Steam Generator Water Level Controller which is the plant policy when manual SG feeding is in progress. The BOP operator was counseled regarding the importance of maintaining a continuous watch on operations in progress or else requesting relief if needed. The SS was advised of the necessity to comply with plant practice to have a dedicated SGWLC when manual SG feeding is in progress. This item was formally discussed following the enforcement conference on March 22, 1989. This item represents a violation of NRC requirements which meets the criteria for non-citation. In order to track this item, the following licensee-identified item is established.

NCV 50-425/89-15-11, "Failure To Exercise The Duties And Responsibilities Of The RO And SS As Delineated In Operations Procedure 10000-C - LER 50-425/89-08."

(q) *50-425/89-11, Rev. 0, "Valve Closure Leads To Non-Compliance With Technical Specifications."

Technical Specification 3/4.5.2 requires that the Safety Injection Pump Cold Leg Injection valve 2-HV-8835 be open while in Modes 1, 2, and 3. On March 19, 1989, the shift operating crew closed the Safety Injection pump cold leg injection valve to the Reactor Coolant System cold Legs (2HV-8835) while performing the system operating procedure to fill SI accumulators at low RCS pressure in Mode 3. Closure of this valve prevents both SI pumps from being capable of providing automatic injection to the RCS cold legs upon receipt of a SI actuation signal. On March 26, while considering LER 2-89-003 (both trains of Residual Heat Removal rendered inoperable due to common valve manipulations) and similar situations for other safety-related systems, a shift supervisor realized that the system operating procedure for filling SI accumulators at low RCS pressure requires closure of 2HV-8835 while in Mode 3. Upon discovering th a review of the Unit 1 and Unit 2 accumulator fills was nitiated. Nine separate instances were identified for Unit 1 when 1-HV-8835 was closed while in Mode 3, in addition to the single occurrence on Unit 2, specified previously. The cause of these events is inadequate procedures which did not prevent closure 2HV-8835 during Mode 3 or require accumulator fill prior to Mode 3 entry. The procedures are being changed to correct these inadequacies. Future followup on this LER corrective actions will be in closeout of the violation.

This event is one example of violation 50-424/89-14-01 and 50-425/89-15-01, "Failure To Establish An Appropriate Procedure To Maintain SI Operable While Filling Accumulators.

(r) *50-425/89-14, Rev. 0, "Feedwater Isolation Results From Error In Startup Test Procedure."

On April 3, Unit 2 startup testing was in progress. A test signal was incorrectly inputted into the steam dump control circuit causing the steam dumps to fully open instead of opening 10% to 15% as expected. This led to a steam generator water level swell and a feedwater isolation due to SG #4 reaching the high-high level. Main feedwater isolation occurred as designed, and the safety grade isolation valves closed, but main feed pump "A" did not trip. As a result, the Auxiliary Feedwater system did not automatically start, although it was already being used to supply SG water. Manual control was taken of the Steam Generator Feed and unit parameters were stabilized. The test procedure, which called for an incorrect test signal, was corrected and the remaining startup tests are being reviewed to ensure that proper connections are specified. Sliding links associated with MFP "A" circuits were found open and are believed to be an oversight from the Unit 2 construction phase. Similar sliding links were inspected to ensure closure.

This item is part of one example of violation 50-424/89-14-01 and 50-425/89-15-01 discussed in paragraph 3.

(s) *50-425/89-15, Rev. 0, "Faulty Circuit Cards Results In ESF Actuations."

On April 5, 1989, a spurious trip of Main Feedwater Pump "A" generated a Feedwater Isolation signal and automatic actuation of the Auxiliary Feedwater System. On April 7, a

FWI and AFW actuation occurred when a steam generator reached its high-high level setpoint during a test of a Main Feedwater Isolation Valve. On April 9, a second spurious trip of MFP "A" generated a FWI and subsequent AFW actuation. The cause of the April 5 and April 9 events was faulty circuit boards in the Solid State Protection System logic circuits. The April 7 event, although not directly caused by a faulty circuit card, was a consequence of the valve lineup used to functionally test repairs made following the April 5 event. The lineup of long-cycle recirculation was not properly restored prior to resumption of startup testing. Corrective actions include replacing the faulty circuit boards and counseling plant operators regarding proper shift turnover of unusual plant configurations and the need for procedural compliance.

This event is part of one example of violation 50-424/89-14-01 and 50-425/89-15-01 discussed in paragraph 3.

One example of a cited violation and thirteen non-cited violations were identified.

5. Actions on Previous Inspection Findings - (92701)(92702)

a. (Closed) Violation 50-424/87-30-03, "Failure To Properly Close Valve."

The inspector reviewed the licensee response dated July 13, 1987. Valve No. 1-1208-U4-348 has had the lock removed to preclude future errors in positioning from the remote operator.

b. (Closed) Violation 50-424/88-05-02, "Lack Of Material Control."

The inspector reviewed the licensee response dated March 10, 1988. The inspector noted that procedures exist to control the purchase and receipt of weld rod.

c. (Closed) Violation 50-424/88-24-01, "Failure To Adequately Design And Install Water Tight Penetration Seals And Perform An Analysis Which Evaluates Their Failure."

The inspector reviewed the licensee response dated September 15, 1988 and reviewed completed MWOs 18900130 and 18900180. During this inspection period, a similar actuation of the fire suppression system occurred which challenged the seal configuration. Observation by the NRC inspector at that time noted that no water penetrated into the Control Room.

d. (Closed) IFI 50-424/88-43-01, "Verify Resolution Of Restoring The SSMP To A Condition To Correctly Indicate The Operability Status."

The licensee corrected the condition by implementing a design change which removed the Boric Acid Pump Motor handswitches as an input to the SSMP. The inspector verified the change was implemented on Unit 1. Following the verification, the inspector noted that Unit 2 had not implemented a similar change. The inspector was informed that design change MDD 89-V2M039 was being developed for Unit 2. The inspector considered the late implementation of a Unit 2 change to be a weakness in the area of engineering support in maintaining the designs both units identical as possible. This change involves the lifting of two leads in each train panel. To track the accomplishment of Unit 2 change, the following inspector followup item is identified.

IFI 50-425/89-15-03, "Verify Resolution Of Restoring The SSMP To A Condition To Correctly Indicate The Operability Status."

e. (Closed) Violation 50-424/88-56-01, "Failure To Implement Operations Procedure 14900-1, Containment Exit Inspection Required By TS 6.7.1."

The inspector reviewed the licensee response dated March 7, 1989. Corrective actions have been observed in practice by the inspector. Procedure 43006-C was revised to include controls for health physics responsibilities.

f. (Closed) Unresolved Item 50-424/88-56-02, "Review Licensee Evaluation Of Compliance To 10 CFR 50.62."

This item concerned the sensitivity of unit personnel to the proper operation and maintenance of AMSAC equipment. The licensee has implemented quarterly and refueling surveillances procedure 54804-1, revised response procedure 54804, and revised response procedure 17005-1. Unit operating procedures 12004-C has been revised to the correctly indicate the power level where the equipment becomes operational. Failure to comply with 10 CFR 50.62 was the result of a failure to establish adequate procedures. Failure to comply with 10 CFR 50.62 was the result of a failure to establish adequate procedures.

This itum is considered to be one of the examples of violation 50-424/89-14-01 and 50-425/89-15-01, "Failure to establish adequate procedures to ensure AMSAC was available.

g. (Closed) Violation 50-424/88-61-01, "Failure To Implement Operations Procedure 10001-C, Required By TS 6.7.1a, To Annotate And Verify Proper Operations Of Control Room Chart Recorders."

In the licensee response dated March 7, 1989, to the Notice dated January 20, 1989, the licensee committed to full compliance on January 31, 1989, upon issuance of standing order C-89-01. This standing order was reviewed by the resident inspector on March 24, 1989, and was found to be satisfactory.

One example of a cited violation and one inspector followup item were identified.

6. Exit Interviews - (30703)

The inspection scope and findings were summarized on May 5, 1989, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection results. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspector during this inspection. Region based NRC exit interviews were attended during the inspection period by a resident inspector. This inspection closed five violations (paragraph 5), one unresolved item (paragraph 5), one inspector followup item (paragraph 5), and nineteen Licensee Event Reports (paragraph 4.b(3)). The items identified during this inspection were:

Violation 50-424/89-14-01 and 50-425/89-15-01 contains six examples where procedures were not either established or implemented as follows:

- "Failure To Implement Procedures 00101-C and 50009-C Resulting In TS 6.7.1.a Violation" - paragraph 2.b(1)

- "Failure to Implement Procedure 12004-C Step 4.1.3g and 4.1.4 for Performing Transfer From Auxiliary Feedwater to Main Feedwater" - paragraph 3

- "Failure To Establish An Adequate Procedure For The Testing Of Steam Dumps" - paragraphs 3 and 4.b(3)(r)

- "Failure To Implement Procedure 12004-C To Secure From Long-Cycle Recirculation" - paragraphs 3 and 4.b(3)(s)

- "Failure To Establish An Appropriate Procedure To Maintain SI Operable While Filling Accumulators" - paragraph 4.b(3)(q)

- "Failure to establish adequate procedures to ensure AMSAC was available" - paragraph 5.c

IFI 50-424/89-14-02 and 50-425/89-15-02, "Review Licensee Evaluation Regarding Adjustment Of The P-9 Setpoint When Steam Dumps Are Removed From Service" - paragraph 3

IFI 50-425/89-15-03, "Verify Resolution Of Restoring The SSMP To A Condition To Correctly Indicate The Operability Status" - paragraph 5.d

NCV 50-424/89-14-03, "Failure To Perform Required Testing Per Surveillance Requirements Results In TS 4.3.3.10 Violations - LER 50-424/89-06" - paragraph 4.b(2)(a)

NCV 50-424/89-14-04, "Failure To Take Required Temperatures Results In Inadequately Performed Surveillance Resulting In A TS Violation - LER 50-424/89-07" - paragraph 4.b(2)(b)

NCV 50-424/89-14-05, "Failure To Conduct An Adequate Engineering Review Of The AFW Electrical System Which Led To AFW Inoperability Resulting In a TS 3.7.1.2 Violation - LER 50-424/89-08" - paragraph 4.b(2)(c)

NCV 50-424/89-14-06, "Failure To Follow Procedures While Conducting A Liquid Waste Release Resulting In A TS 3.3.3.9 Violation - LER 50-424/89-10" - paragraph 4.b(2)(d)

NCV 50-424/89-14-07, "Failure To Conduct Surveillance Resulting In A Violation Of TS 4.1.3.2 - LER 50-424/88-30" - paragraph 4.b(3)(h)

NCV 50-425/89-15-04, "Failure To Meet A Mode Change Prerequisite Resulting In A TS 3.7.12 Violation Requiring Valve 2HV-19051 To Be Operable Prior To Entering Mode 4 - LER 50-425/89-05" - paragraph 4.b(2)(e)

NCV 50-425/89-15-05, "Failure To Follow Procedures Resulting In Inadvertent SI Actuation - LER 50-425/89-06" - paragraph 4.b(2)(f)

NCV 50-425/89-15-06, "Failure To Establish An Adequate Sampling Procedure For Diesel Fuel Oil Per TS 6.7.1.a - LER 50-425/89-09" - paragraph 4.b(2)(h)

NCV 50-425/89-15-07, "Failure To Obtain A Radioactive Release Permit Prior To Releasing Radioactive Materials To Unrestricted Areas Resulting In A TS 3/4.11.1 Violation - LER 50-425/89-10" - paragraph 4.b(2)(i)

NCV 50-425/89-15-08, "Failure To Follow Procedures While Performing Maintenance On 2RE-2562A Resulting In The Plant Operating In A Condition Prohibited By TS Thus Requiring Entry Into TS 3.0.3 - LER 50-425/89-12" - paragraph 4.b(2)(j)

NCV 50-425/89-15-09, "Failure To Maintain The Auxiliary Feedwater System Operable Resulting In A Condition Prohibited By TS 3.7.1.2. - LER 50-425/89-13" - paragraph 4.b(2)(k)

NCV 50-425/89-15-10, "Failure To Maintain RMWST, Discharge Valves Shut Closed And Secured In Position While In Mode 5 Resulting In TS 3.4.1.4.2 Violation - LER 50-425/89-02" - paragraph 4.b(3)(m)

NCV 50-425/89-15-11, "Failure To Exercise The Duties And Responsibilities Of The RO And SS As Delineated In Operations Procedure 10000-C - LER 50-425/89-08" - paragraph 4.b(3)(p)

The strengths in the areas of maintenance (paragraph 2.b(7)) and startup testing (paragraph 3) and the weakness in the area of operations (paragraphs 3, 4.b(2), and 4.b(3)) were also discussed.

7. Acronyms And Initialism

ABN	As-Built Notice
A/DV	Anchor Darling Valve
AFW	Auxiliary Feedwater System
AMSAC	ATWAS Mitigating System Actuating Circuitry
ASTEC	Automatic Surveillance Technical System
BFIV	Bypass Feed Isolation Valve
BFRV	Bypass Feed Regulation Valve
BOP	Balance-of-Plant
CCP	Centrifugal Charging Pump
CCW	Component Cooling Water System
CFR	Code of Federal Regulations
CRI	Control Room Isolation
CVCS	Chemical & Volume Control System
CVI	Containment Ventilation Isolation
DC	Deficiency Cards
DFOS	Diesel Fuel Oil Storage
DPIS	Digital Position Indication System
DRPIS	Digital Rod Position Indication System
ECCS	Emergency Core Cooling System
ERF	Emergency Response Facility
ESF	Engineered Safety Feature
FI	Flow Indicator
FWI	Feedwater Isolation
GE	General Electric
GPM	Gallons Per Minute
HS	Hand Switch
HV	High Voltage
I&C	Instrument and Control
IFI	Inspector Followup Item
ISEG	Independent Safety Engineering Group
LCO	Limiting Condition for Operation
LER	Licensee Event Reports
LLRT	Local Leak Rate Test
LOSP	Loss of Offsite Power
MDAFW	Motor Driven Auxiliary Feedwater System Pump
MDD	Minor Departure from Design
MFIV	Main Feedwater Isolation Valve
MFP	Main Feed Pump
MFW	Main Feedwater
MOV	Motor Operator Valve
MWO	Maintenance Work Order
NCV	Non-cited Violation
NPF	Nuclear Power Facility
NR	Narrow Range
NRC	Nuclear Regulatory Commission
NSCW	Nuclear Service Cooling Water
NUE	Notice of Unusual Event
OSOS	On-Shift Operation Supervisor

PERMS	Plant Effluent Radiation Monitoring System
PORV	Power Operated Relief Valve
PT	Pressure Transmitter
PV	Pressure Valve
RCDT	Reactor Coolant Drain Tank
RCS	Reactor Coolant System
RHR	Residual Heat Removal System
RMWST	Reactor Makeup Water Storage Tank
RO	Reactor Operator
RPDM	Rod Position Deviation Monitor
RWST	Reactor Water Storage Tank
SAER	Safety Audit and Engineering Review
SG	Steam Generator
SGWLC	Steam Generator Water Level Control
SI	Safety Injection System
SS	Shift Supervisor
SSMP	Safety System Monitor Panel
TDAFW	Turbine Driven Auxiliary Feedwater Pump
TS	Technical Specification
TSC	Technical Support Center

Approval	Vogtle Electric Generating Plant NUCLEAR OPERATIONS	Procedure No. 00304-C
S Bockhold		Revision No. 14
Date 5/23/88	Unit COMMON Georgia Power	Page No. 1 of 43

VOID

EQUIPMENT CLEARANCE AND TAGGING

1.0 PURPOSE

This procedure provides instructions for requesting, issuing, and releasing CLEARANCES on plant equipment or systems to ensure safety of personnel and equipment during maintenance, testing, or inspection. Instructions are included in the following:

4.0 Instructions

4.1 Clearance Philosophy

4.2 Requesting A Clearance

4.3 Preparing The Clearance Sheet

4.4 Clearing And Tagging

4.5 Issuing Subclearances

4.6 Adding Clearance Points

4.7 Performing Functional Tests

4.8 Performing Partial Releases

4.9 Releasing Clearances

4.10 Caution Tags

4.11 Performing Quarterly Checks

2.0 DEFINITIONS

2.1 CLEARANCE

Authorization to work on plant equipment that has been safely isolated by the use of HOLD TAGS

2.2 CLEARANCE NUMBER

The control number assigned to a unique CLEARANCE SHEET and associated red HOLD TAG(S). The CLEARANCE NUMBER will be a 3-part number designating unit number, year issued, and the consecutive number. Example: 1-87-14 would be the fourteenth CLEARANCE SHEET issued in 1987 for unit one or common equipment.

NOTE

Unit Numbers are as follows:

1 = Unit One and Common
2 = Unit Two

2.3 CLEARANCE POINT

All those valves, breakers, switches, etc. that must be positioned to <u>positively</u> clear all sources of electrical power, liquids or gasses from the work area.

2.4 CLEARANCE REQUEST FORM

A form used by PLANT/CONSTRUCTION personnel to request CLEARANCE on a plant component or subsystem. (See Figure 2.)

2.5 CLEARANCE SHEET

The primary means of CLEARANCE documentation. The CLEARANCE SHEET shall consist of a minimum of one sheet, front and back (Figures 3a & 3b). Any Subclearance Continuation Sheets (Figure 3c) also become part of the CLEARANCE SHEET as they are required.

2.6 EXTENDED ACTIVE CLEARANCE

A CLEARANCE which remains in effect for more than 3 months.

2.7 FUNCTIONAL TEST

A test of a component or subsystem to verify satisfactory operation of the component or subsystem, after the component or subsystem has been placed in a configuration that assures plant equipment and personnel safety.

2.8 HOLD TAG

A HOLD tag (Figure 1) which, when attached to a piece of equipment, prohibits the operation of that equipment in all circumstances.

NOTE

White DANGER tags, previously used by this procedure, that are still in the plant will be replaced with red HOLD tags during quarterly checks. This replacement may be conducted sooner at Operators discretion. Danger tags currently in use carry the same authority as the new HOLD TAG.

2.9 HOLD TAG NUMBER

The number placed on each HOLD TAG; derived by using the CLEARANCE NUMBER and the sequential tag number from the CLEARANCE SHEET. Example: 1-87-14-1 would be the first HOLD TAG placed on CLEARANCE 1-87-14; 1-87-14-2 would be the second HOLD TAG placed on the same CLEARANCE.

2.10 INDEPENDENT VERIFICATION

The establishment of completed activity accuracy, implemented by procedure and documented by a qualified individual acting independently from the individual responsible for activity performance.

2.11 RELEASE

Subclearance holder authorization that clearance points are no longer necessary to provide plant equipment or personnel protection.

2.12 PARTIAL RELEASE

The act of releasing one or more CLEARANCE POINTS without releasing the entire CLEARANCE. (See Figure 6)

2.13 QUARTERLY CHECK

A check of EXTENDED ACTIVE CLEARANCES which is performed at three month intervals, based on the CLEARANCE installation date, to verify the following:

a. The equipment is still positioned and tagged as indicated on the CLEARANCE SHEET.

b. The CLEARANCE is still valid and required by plant conditions.

2.14 SUBCLEARANCE

The method by which plant personnel may sign on to a CLEARANCE and perform work under the protection of th CLEARANCE.

2.15 SUBCLEARANCE HOLDER

An individual listed on the Qualified Subclearance Holder List (Figure 7), normally a Plant Supervisor or Foreman (PS/F), who has been issued a SUBCLEARANCE.

2.16 TAGGING DESK

A location in or near the Control Room, under the direction of the Shift Supervisor, where active CLEARANCE books, UNIT CLEARANCE LOGS, and other related forms are kept.

2.17 TAGGING DESK OPERATOR

A qualified Operations Department employee who coordinates activities as described in this procedure.

2.18 UNIT CLEARANCE LOG

An index of CLEARANCES (Figure 4) which contains the following information: CLEARANCE NUMBER, Equipment Description, MWO No. Installed and Released Dates, and any QUARTERLY CHECKS.

2.19 CAUTION TAG

A yellow tag attached to a piece of equipment that provide cautions related to its use or operation. This tag is not to be used to provide personnel protection.

3.0 RESPONSIBILITIES

3.1 RESPONSIBLE POSITIONS FOR RELEASE OF CLEARANCES

3.1.1 General Manager, Plant Manager, and the Plant Support Manager.

The General Manager, Plant Manager, or the Plant Support Manager, is responsible for releasing SUBCLEARANCES if the SUBCLEARANCE HOLDERS cannot be contacted and providing notification to that individual when he/she returns to work.

3.1.2 Unit II Field Construction Manager/Project Construction Manager

During the Initial Test Program the Unit II Field Construction Manager or the Project Construction Manager is responsible for releasing subclearances of construction personnel, if the SUBCLEARANCE HOLDER can not be contacted and providing notification to that individual when he/she returns to work.

3.1.3 The On-Shift Operations Supervisor (OSOS) or the Department Supervisor may release a SUBCLEARANCE if the SUBCLEARANCE HOLDER is off-site, and gives permission by phone.

3.1 The OSOS and Department Supervisor may release a SUBCLEARANCE if the SUBCLEARANCE HOLDER is off-site, and cannot be contacted. They are also responsible for providing notification to that individual when he/she returns to work.

3.2 DEPARTMENT MANAGERS/SUPERINTENDENTS

The department heads are responsible for:

3.2.1 Assigning their personnel to attend CLEARANCE training provided by the Training Department.

3.2.2 Notifying the Manager Operations in writing, of their Plant Supervisors/Foremen (PS/F) who have successfully completed CLEARANCE training and have been qualified to be SUBCLEARANCE HOLDERS. This is done by completing Figure 7.

3.3 MANAGER OPERATIONS

The Manager Operations is responsible for:

3.3.1 Implementation of this procedure.

3.3.2 Ensuring QUARTERLY CHECKS are completed.

3.3.3 Ensuring that the personnel who implement this procedure are qualified by demonstrated ability and procedural knowledge.

3.4 TRAINING DEPARTMENT

The Training Department is responsible for:

3.4.1 Providing CLEARANCE training when required by department superintendents.

3.4.2 Providing department superintendents with a list of their personnel who successfully complete CLEARANCE training.

3.5 SHIFT SUPERVISOR

The Shift Supervisor is responsible for:

3.5.1 Obtaining permission from the System Operator before issuing any CLEARANCE which might affect the load carrying capability of the unit.

NOTE

If continued operation of equipment important to the load carrying capability of the unit may endanger personnel, that equipment may be removed from service without the permission of the System Operator. The System Operator will be notified as soon as possible.

3.5.2 Signing for the System Operator to initiate or release a subclearance when so requested by the System Operator.

3.5.3 Maintaining a current list of those employees qualified to implement this procedure and a list of those qualified to be SUBCLEARANCE HOLDERS.

3.5.4 Issuing and releasing CLEARANCES.

3.5.5 Ensuring the UNIT CLEARANCE LOG and the UNIT CAUTION LOG for each unit are maintained.

3.5.6 Preparing and/or authorizing the CLEARANCE SHEET after reviewing the impact of the CLEARANCE on plant operations.

3.5.7 Preparing and/or authorizing FUNCTIONAL TESTS and PARTIAL RELEASES.

3.5.8 Verifying that all applicable Technical Specifications action statements are followed when issuing a CLEARANCE.

3.5.9 Calling the Fire Protection Engineer when issuing or releasing a CLEARANCE on any Fire Protection equipment.

3.6 OPERATIONS DEPARTMENT EMPLOYEES

Operations Department employees are responsible for:

3.6.1 Reviewing and approving CLEARANCE REQUEST FORMS.

3.6.2 Reviewing/preparing CLEARANCE SHEETS, HOLD TAGS, FUNCTIONAL TEST and PARTIAL RELEASE forms.

3.6.3 Maintaining the UNIT CLEARANCE LOG and the UNIT CAUTION LOG

3.6.4 Performing equipment alignment and hanging and removing HOLD TAGS as necessary to implement this procedure.

3.6.5 Performing INDEPENDENT VERIFICATION as required.

3.6.6 Performing QUARTERLY CHECKS of EXTENDED ACTIVE CLEARANCES.

3.7 PLANT SUPERVISOR OR FOREMAN

NOTE

During the Initial Test Program the term PS/F may include construction area coordinators and engineers/ supervisors who have successfully completed CLEARANCE training and are on the authorization list.

A PS/F is responsible for:

3.7.1 Obtaining a SUBCLEARANCE, when required, before allowing the performance of work which the PS/F is responsible for completing.

3.7.2 Verifying that the CLEARANCE is <u>adequate</u> for the work to be performed before work begins.

3.7.3 Informing each crew member of the limits of that CLEARANCE when directing a crew to perform work under that CLEARANCE.

3.7.4 Releasing the SUBCLEARANCE when the PS/F's crew has completed their portion of the work requiring the SUBCLEARANCE.

3.7.5 Releasing the SUBCLEARANCE if the PS/F is to be away for an extended period of time. These SUBCLEARANCES shall be reissued to the PS/F's qualified replacement if the work is incomplete.

3.8 PLANT PERSONNEL

It is the responsibility of all plant personnel to adhere to the requirements of this procedure.

3.9 INDEPENDENT VERIFIER

The Operations Department Individual who is responsible for verifying the position of a safety-related component as described on the CLEARANCE SHEET in accordance with the provisions of Procedure 00308-C, "Independent Verification Policy".

4.0 INSTRUCTIONS

4.1 CLEARANCE PHILOSOPHY

4.1.1 When clearing power supplies to solenoids remove fuses, where practical, instead of links. Fuses shall be bagged and HOLD tagged as part of the CLEARANCE. No more than two fuses per bag.

4.1.2 The scope of each CLEARANCE should be just enough to adequately clear the equipment. This is to reduce interference with other CLEARANCES, and use of PARTIAL RELEASES.

4.1.3 When HOLD tagging a Motor Operated Valve (MOV) as a fluid boundary, the handswitch shall be HOLD tagged in the position in which the valve handwheel will be HOLD tagged. The breaker shall be opened or off, as applicable, and the handwheel shall be HOLD tagged.

4.1.4 When using Air Operated Valves (AOV) as boundary valves perform the following:

4.1.4.1 For a FAIL CLOSE AOV

a. HOLD tag the handswitch in the closed position

b. HOLD tag the air supply valve closed and check that the air line to the valve is depressurized.

c. If the valve has a handwheel, HOLD tag it in the closed position.

4.1.4.2 For a FAIL OPEN AOV with handwheel

a. HOLD tag the handswitch in the closed position

b. HOLD tag the handwheel in the closed position

4.1.4.3 For a FAIL OPEN AOV without handwheel

a. HOLD tag the handswitch in the closed position

b. Mechanically or hydraulically (as appropriate) gag the valve in the closed position and HOLD tag the gagging device.

4.1.5 When restoring Air Operated Valves used as boundary valves perform the following

4.1.5.1 For a FAIL CLOSE AOV

a. If the valve has a handwheel, remove the handwheel HOLD tag and restore to the operate or open position.

b. Remove the HOLD tag from and open air supply valve

c. Remove HOLD tag from handswitch and oper te as required.

4.1.5.2 For a FAIL OPEN AOV with handwheel

a. Remove HOLD tag from handwheel and place handwheel in the open position.

b. Remove HOLD tag from handswitch and operate as required.

4.1.5.3 For a FAIL OPEN AOV without handwheel

a. Remove HOLD tag from gagging device and remove gag.

b. Remove HOLD tag from the handswitch and operate as required.

4.1.6 The handswitch position on HOLD TAGS shall be in the same position as the controlled compc nent, e.g. A handswitch tagged closed means the valve is closed. If a difference exists due to unforeseen circumstances an information tag sha.l be attached to the handswitch <u>and</u> the CLEARANCE stating conditions. An example may be: The motor of a MOV is burned out and manual operation is necessary.

4.1.7 HOLD TAGS should be placed in a manner that they will be easily visible to anyone preparing to operate the equipment.

4.1.8 A FUNCTIONAL TEST is intended to allow testing of equipment after it has been repaired. The FUNCTIONAL TEST should not extend for more than 4 days. If the test will last more than 4 days the CLEARANCE shall be partially or fully released.

4.1.9 When HOLD tagging valves with remote operators (reach rods) place the valve in the position required on the clearance sheet and only HOLD tag the external handwheel or operator. Verify the clutch is engaged when operating the valve, if applicable.

4.1.10 When isolating a fluid filled system, or portion of a system, that will be opened to the atmosphere for maintenance, the clearance should include a vent and a drain that will drain that portion of the system to be worked.

4.1.11 If a clearance has more than one subclearance holder the CLEARANCE shall not be modified for one subclearance holder without the concurrence of all subclearance holders. Example: MCC breaker tagged off and Locked (door closed), you may not remove the lock, open the door and RELOCK the breaker (door open) without the approval of all subclearance holders

4.1.12 Should a clearance be voided after it has been assigned a number the word "VOID" shall be written on each page and the individual voiding the clearance shall initial and date each page. It should then be canceled from the log, sent to the Shift Clerk and handled the same as a released clearance.

WARNING

NO HOLD TAG SHALL BE ATTACHED OR REMOVED WITHOUT AUTHORIZATION FROM THE SHIFT SUPERVISOR.

4.2 REQUESTING A CLEARANCE

NOTE

The TAGGING DESK will be manned by the TAGGING DESK OPERATOR during periods of increased work activity to assist the Shift Supervisor in implementing this procedure.

4.2.1 A CLEARANCE is requested by completing a CLEARANCE REQUEST FORM (Refer to Figure 2) and submitting it to the TAGGING DESK OPERATOR, Shift Supervisor, or Operations Work Planner preferably at least 24 hours prior to the time needed.

4.2.2 The requesting individual shall provide the following information:

a. A Description of Equipment/System to be Cleared. (Example: Motor-Driven Fire Pump)

b. The tag number for that equipment, (Example: C-2301-P4-002)

c. The Reason for the CLEARANCE,

d. The Estimated Outage Time

e. All Associated Work Order Numbers,

f. Requested and Needed Dates and Times,

g. Name of Requesting PS/F and Extension,

h. Recommended CLEARANCE POINTS and their positions,

i. Reference Drawings

4.3 PREPARING THE CLEARANCE SHEET

NOTE

Computer generated clearance sheets may be used.

4.3.1 The Shift Supervisor, Operations Work Planner, or TAGGING DESK OPERATOR will review the CLEARANCE REQUEST FORM and the plant status to determine whether the CLEARANCE can be issued. If he determines that the CLEARANCE can be issued, he will ensure that the CLEARANCE POINTS are adequate for personnel and/or equipment protection before preparing the CLEARANCE SHEET (Refer to Figures 3a & 3b.)

4.3.2 The Shift Supervisor, Operations Work Planner, or TAGGING DESK OPERATOR will prepare the CLEARANCE SHEET:

a. Complete the following spaces on the UNIT CLEARANCE LOG (Typical of Figure 4): CLEARANCE NUMBER, Description of Cleared Equipment, and MWO Number (if applicable).

b. Complete the information above the double-line on the front of the CLEARANCE SHEET. (Figure 3a)

WARNING

RELAYS, CHECK VALVES, SOLENOID VALVES AND AIR OPERATED VALVES ENERGIZED IN THE DESIRED POSITION SHALL NOT BE USED AS CLEARANCE POINTS. EXCEPT AS NOTED IN THE FOLLOWING. A HOLD TAG SHALL NOT BE PLACED ON ANY COMPONENT WHICH IS ENERGIZED WITHOUT THE COMPONENT BEING MECHANICALLY BLOCKED IN THE DESIRED POSITION.

c. Complete the information on the back of the CLEARANCE SHEET (Figure 3b). This should include: CLEARANCE NUMBER, HOLD TAG NUMBER, Equipment Name and Number, and Required Position.

d. Complete the "Prepared by" and "Locked Valves" spaces on the front of the CLEARANCE SHEET. The "Locked Valves" space should be checked "yes" if the CLEARANCE requires the manipulation of locked valves.

e. Submit the CLEARANCE SHEET to the Shift Supervisor for review and authorization.

4.3.3 If the Shift Supervisor agrees that the CLEARANCE can be issued, he will do the following:

a. Perform or assign an individual to review the CLEARANCE for adequate protection of personnel and/or equipment. Reviewer shall sign the reviewed by blank on the CLEARANCE SHEET.

b. Review CLEARANCE for safety-related items, ensure that all Technical Specification action statements can be met, and check the appropriate "Involves Tech. Spec. Safety-Related Item" space on the front of the CLEARANCE SHEET.

NOTE

Step 4.3.3c is required only after receipt of the Unit Operating License.

c. Provide explicit notification to the Reactor Operator that a safety-related system is being removed from service. Such notification shall be recorded in the Unit Control Log.

d. When CLEARANCE operations result in a safety-related component or system being inoperable, the Shift Supervisor shall ensure that all required surveillances on the redundant train are performed as required.

e. If a Clearance involves Fire Protection Equipment:

(1) Notify the Fire Protection Engineer (FPE), or designee, during normal work hours.

(2) If the FPE, or designee, cannot be reached during non-normal work hours (weekends, holidays or nights), contact the Duty Engineer.

NOTE

The FPE, designee, or Duty Engineer, as appropriate shall notify the Corporate Insurance Representative if the impairment will last more that ight hours or includes a shift change.

f. Review the request to see if the load carrying capability of the plant may be affected.

g. Record the date and time and sign the "Authorized by" space on the front of the CLEARANCE SHEET.

NOTE

CLEARANCES may also originate in the form of written switching orders issued by the System Operator or Division Operator. These switching orders will constitute the plant's permanent record of these CLEARANCES. These will be executed in accordance with the latest edition of the "Electric System Operation" procedure, published by the Georgia Power Company Operating Department. ("The Red Book")

4.4 CLEARING AND TAGGING

4.4.1 A qualified operator when clearing and tagging, will do the following:

a. Write the following on the HOLD TAG(S): (Figure 1)

(1) HOLD TAG NUMBER (Example: 1-87-14-1)

(2) Specified Position.

(3) Equipment Identification Number (Examples: HS-7907B, 1AA02-10, C2301-U4-660)

NOTE

Computer generated labels with the same information may also be used.

b. Have the authorized CLEARANCE SHEET in his possession when performing clearing and tagging operations.

c. The Shift Supervisor should be notified immediately of multiple HOLD TAGS and should make the decision as to the position that affords the highest degree of personnel protection.

d. Operate equipment and attach HOLD TAGS as described below in sequence, from the top of the page to the bottom of the page, and initialing the appropriate space as each step is completed.

(1) For switchgear breakers, HOLD TAGS shall be placed on the cubicle door. (The HOLD TAG does not prevent removal of the breaker for maintenance purposes.)

(2) 480VAC MCC breakers shall be operated as follows:

(a) Operations personnel shall operate the breaker per 13435-C, "Circuit Breaker Racking Procedure" and place a HOLD TAG on the breaker switch lock ring. If the CLEARANCE is for physical work on that breaker, then the HOLD TAG shall be placed on the cubicle door and the lock placed on the lock ring after the door is opened.

NOTE

Construction craftmen will work under the Operations lock installed in step (a), if applicable. The following steps (b), (c), (d), (e) and (f) apply to Georgia Power Company, IBEW personnel only.

(b) Any Georgia Power Company, IBEW Electrician performing maintenance on equipment supplied by the breaker will obtain the padlock key along with a numbered lock and key from the Control Room, remove the HOLD TAG, unlock the breaker, and verify de-energization of the load side using a suitable multimeter without operating the breaker.

(c) Following verification of load side de-energization, the Electrician shall close the cubicle door and relock the breaker switch with the numbered lock, and rehang the HOLD TAG.

(d) The operations padlock and key will be returned immediately to the control room. The numbered key will be held by the Electrician's Foreman until work is complete at which time it shall be returned to the control room.

(e) Any Georgia Power Company, IBEW Mechanic performing maintenance on equipment supplied by the breaker will request that an Electrician verify de-energization of the load side. In this event, steps (b) and (c) above shall be followed.

(f) The operations padlock and key will be returned immediately to the control room. The numbered key will be held by the Mechanic's Foreman until work is complete at which time it shall be returned to the Control Room. The Operations Department will remove the HOLD tag and numbered lock and re-energize the breaker only after all SUBCLEARANCES have been released.

(3) For 480V AC power panels, AC and DC distribution panels the HOLD TAG shall be placed conspicuously adjacent to the breaker.

NOTE

Independent Verification is required only after receipt of the Unit Operating License.

4.4.2 The operator shall initial each CLEARANCE POINT as indicated and sign and date the space provided on the CLEARANCE SHEET. The Shift Supervisor shall ensure INDEPENDENT VERIFICATION is performed when required.

4.4.3 Upon completion of the clearing and tagging, the Shift Supervisor or TAGGING DESK OPERATOR shall review the CLEARANCE SHEET for completeness, place it in the active CLEARANCE books and initial and date the UNIT CLEARANCE LOG in the space provided.

4.4.4 The Shift Supervisor or TAGGING DESK OPERATOR should then notify the applicable PS/F that the CLEARANCE is ready for SUBCLEARANCE issue.

4.5 ISSUING SUBCLEARANCES

4.5.1 The responsible PS/F shall verify that the CLEARANCE is adequate for the work his crew will perform.

4.5.2 If the CLEARANCE is inadequate, additional CLEARANCE POINTS may be added by request of the PS/F. The additional CLEARANCE POINTS shall receive the same review as the original CLEARANCE.

4.5.3 The Shift Supervisor or tagging desk operator may issue a SUBCLEARANCE to a qualified PS/F by having the PS/F record the MWO, CAT Number or other work document, the date, time, and sign the "Issued To" Section on the front of the CLEARANCE SHEET.

NOTES

a. If the SUBCLEARANCE does not have a work document, the purpose for a SUBCLEARANCE shall be written in this space.

b. Subclearances may be requested by the System Operator (SO) by telephone. The Shift Supervisor will sign for the SO ("Shift Supervisor for System Operator") on the clearance sheet.

4.5.4 If there are more SUBCLEARANCE HOLDERS than spaces provided, the Shift Supervisor or TAGGING DESK OPERATOR will attach a SUBCLEARANCE Continuation Sheet (Figure 3c) immediately behind the CLEARANCE SHEET, and check the "yes" box on the CLEARANCE SHEET.

4.5.5 If maintenance is to be performed (i.e., the CLEARANCE is for personnel protection), the PS/F shall, for 480V AC power panels, lift leads from the breaker in accordance with Procedure 00306-C, "Temporary Jumper And Lifted Wire Control" or Procedure 20429-C, "Short Term Documentation Of Temporary Jumpers And Lifted Wires" depending upon the length of time that the maintenance will take.

4.5.6 If no maintenance is to be performed (i.e., the CLEARANCE is for equipment protection), the PS/F may lift the leads for 480 VAC power panels as described in Step 4.5.5 if desired.

4.5.7 The PS/F will inform each member of his crew of the limits of the CLEARANCE before work begins.

4.5.8 When a PS/F wishes to release his SUBCLEARANCE, he will verify that all grounding devices which he or his crew may have installed are removed. He will then report to the Shift Supervisor or TAGGING DESK OPERATOR, sign and record date and time in the appropriate space on the CLEARANCE SHEET. The sign-off by the System Operator will be done by the Shift Supervisor, when requested by telephone.

4.6 ADDING CLEARANCE POINTS TO AN EXISTING CLEARANCE

4.6.1 To add points to an existing clearance complete the top part of Figure 12 "Additional Clearance Point Form" and submit to the SS or Tagging Desk Operator.

4.6.2 The SS or Tagging Desk Operator will review the request to determine if the additional points can be added to the clearance. After ensuring the clearance points are adequate the Shift Supervisor will sign the "Approved by" space.

4.6.3 All subclearance holders on the existing clearance must be notified of the additional points and approve of the addition. The subclearance holders will complete the spaces in the subclearance block on the Figure 12 to show their approval. Approval may be obtain by telephone if so noted.

4.6.4 The additional clearance points will be added to the existing clearance form <u>AFTER</u> the SS and subclearance holders have approved the addition.

4.6.5 After approval the additional clearance points may be installed, documented on the clearance sheet, and signed for on Figure 12.

4.7 PERFORMING FUNCTIONAL TESTS

WARNING

SUBCLEARANCE RELEASE FOR TEST BY ALL SUBCLEARANCE HOLDERS MUST BE OBTAINED BEFORE ANY FUNCTIONAL TESTS CAN BE AUTHORIZED.

NOTE

If there are no SUBCLEARANCE HOLDERS, The CLEARANCE should be released per Section 4.8. This Section is inappropriate for use.

4.7.1 The Shift Supervisor or TAGGING DESK OPERATOR will normally complete a FUNCTIONAL TEST form (Figure 5) upon request from a PS/F.

4.7.2 The individual (PS/F or the SS) requesting a release will have the responsibility for obtaining releases from all of the SUBCLEARANCE HOLDERS for the test. Each SUBCLEARANCE HOLDER will be responsible for notifying his crew of the test.

4.7.3 After all SUBCLEARANCE HOLDERS have released their SUBCLEARANCE for FUNCTIONAL TEST, the Shift Supervisor or TAGGING DESK OPERATOR will attach the FUNCTIONAL TEST form to the CLEARANCE SHEET and submit to the Shift Supervisor.

4.7.4 The Shift Supervisor shall ensure that all SUBCLEARANCE HOLDERS have released their SUBCLEARANCE before authorizing the FUNCTIONAL TEST.

4.7.5 After approval the Shift Supervisor will provide a qualified operator to perform the test and operate the equipment as requested by the requesting PS/F.

NOTE

Prior to fuel load, the Shift Supervisor may authorize a maintenance department person (i.e., electrician, mechanic, or I&C technician) to remove/ install tags during the functional test. If this occurs, the maintenance department person shall assume all applicable operator responsibilities described in Section 4.7.

4.7.6 The operator performing the FUNCTIONAL TEST shall:

a. Have the CLEARANCE SHEET with the attached authorized FUNCTIONAL TEST form in his possession before removing any HOLD TAGS.

b. Remove HOLD TAGS, position the equipment, and initial each step as indicated on the FUNCTIONAL TEST form in the proper sequence (the top line is the first step and the bottom line is the last).

c. Sign and record date and time on the FUNCTIONAL TEST form when all CLEARANCE POINTS are released.

d. Attach Functional Test Tag (Figure 3) to any handswitch from which a hold tag was removed, or which is associated with equipment under functional test even if not previously tagged.

e. Operate the equipment only as directed by the requesting PS/F.

f. Return the CLEARANCE SHEET with the attached FUNCTIONAL TEST form and HOLD TAGS to the Control Room if the test will require more than 2 hours to complete. The Shift Supervisor or TAGGING DESK OPERATOR will then place these in the FUNCTIONAL TEST log book.

4.7.7 After the FUNCTIONAL TEST has been completed, the CLEARANCE points will be restored to the original status as indicated on the CLEARANCE SHEET. The restoration sequence should be as directed by the requesting PS/F unless the CLEARANCE is to be released.

4.7.8 The operator will position the equipment as indicated, reattach the HOLD TAGS, remove any FUNCTIONAL TEST TAGS, and initial each restoration step.

4.7.9 When the CLEARANCE is restored, the operator will sign and record date and time in the space provided on the FUNCTIONAL TEST form. The Shift Supervisor shall ensure INDEPENDENT VERIFICATION is performed when required.

4.7.10 The operator will then return the CLEARANCE SHEET with the attached FUNCTIONAL TEST form to the Shift Supervisor or TAGGING DESK OPERATOR.

4.7.11 The CLEARANCE SHEET with the attached FUNCTIONAL TEST form shall then be returned to the active CLEARANCE books.

4.7.12 If the CLEARANCE is to be released after the FUNCTIONAL TEST is complete, the operator shall return the FUNCTIONAL TEST TAGS, CLEARANCE SHEET with the attached FUNCTIONAL TEST form and HOLD TAGS to the Shift Supervisor for release of the CLEARANCE (See Subsection 4.9).

4.8 PERFORMING PARTIAL RELEASES

4.8.1 The Shift Supervisor or TAGGING DESK OPERATOR will formally complete a PARTIAL RELEASE form (Figure 6) upon request from a PS/F.

4.8.2 The requesting PS/F (or SS if applicable) will have the responsibility of obtaining releases from all SUBCLEARANCE HOLDERS before a PARTIAL RELEASE can be authorized.

NOTE

Two or more separate CLEARANCE points may be released on a single PARTIAL RELEASE form.

4.8.3 After all SUBCLEARANCE HOLDERS have released the CLEARANCE POINTS for PARTIAL RELEASE, the Shift Supervisor or TAGGING DESK OPERATOR will attach the PARTIAL RELEASE form to the CLEARANCE SHEET and indicate on the back of the CLEARANCE SHEET the removal sequence and position of the equipment to be released.

4.8.4 The Shift Supervisor will then evaluate the PARTIAL RELEASE to determine if it compromises personnel or equipment safety. If so, the PARTIAL RELEASE shall not be authorized.

4.8.5 The Shift Supervisor shall ensure that all SUBCLEARANCE HOLDERS have released the CLEARANCE POINTS for PARTIAL RELEASE before authorizing the PARTIAL RELEASE.

4.8.6 The Shift Supervisor will sign and record date and time on the PARTIAL RELEASE form and return the CLEARANCE SHEET with the attached PARTIAL RELEASE form to the TAGGING DESK OPERATOR.

4.8.7 The Shift Supervisor will then provide a qualified operator to perform the PARTIAL RELEASE.

4.8.8 The operator performing the PARTIAL RELEASE shall:

a. Have the CLEARANCE SHEET with the attached authorized PARTIAL RELEASE form in his possession before removing any HOLD TAGS.

b. Remove HOLD TAGS, position the equipment, and initial each step as indicated on the CLEARANCE SHEET in the proper sequence (Perform the step labeled "1" first).

c. Sign and record date and time on the PARTIAL RELEASE form.

d. Return the CLEARANCE SHEET with the attached PARTIAL RELEASE form and HOLD TAG(S) to the Shift Supervisor or TAGGING DESK OPERATOR. If the HOLD TAGS are contaminated with radioactive material, they shall be disposed of as radioactive trash and the Shift Supervisor or TAGGING DESK OPERATOR informed of their disposal.

4.8.9 The Shift Supervisor shall ensure INDEPENDENT VERIFICATION is performed as required. Upon completion, the operator shall initial each step on the back of the CLEARANCE SHEET and sign and record date and time in the space provided on the PARTIAL RELEASE form.

4.8.10 The Shift Supervisor or TAGGING DESK OPERATOR will ensure that the PARTIAL RELEASE is complete, destroy the returned HOLD TAGS, and place the CLEARANCE SHEET with the attached PARTIAL RELEASE form in the active CLEARANCE books.

4.9 RELEASING CLEARANCES

WARNING

ALL SUBCLEARANCES MUST BE RELEASED BEFORE A CLEARANCE CAN BE RELEASED.

4.9.1 Upon a request from a PS/F, the Shift Supervisor or TAGGING DECK OPERATOR should:

a. Ensure that all SUBCLEARANCES are released.

b. Evaluate plant status to determine if the CLEARANCE can be released.

c. If the clearance includes Fire Protection Equipment, NOTIFY the Fire Protection Engineer, or designee, and request concurrence with the release. If the FPE, or designee, is not available, contact the Duty Engineer.

d. Specify the removal sequence and desired position of each CLEARANCE point on the back of the CLEARANCE SHEET. The SS or Tagging Desk Operator will utilize the normal system alignment, in accordance with the normal system line-up procedure (11XXX-X), as modified by existing CAUTION TAGS, Information Tags, etc. when specifying removal position and sequence. If the removal process does not result in restoration to normal system alignment the SS will ensure the off-normal condition is properly documented via Caution tags, Information tags, etc. (The removal sequence shall be specified by placing a "1" adjacent to the first step, a "2" adjacent to the second step, etc.)

e. Submit the CLEARANCE SHEET to the Shift Supervisor.

4.9.2 The Shift Supervisor shall ensure that all SUBCLEARANCES have been released and that the CLEARANCE can be released before signing the authorization to release.

4.9.2.1 If the Nuclear Operation or Construction SUBCLEARANCE HOLDER (SCH) is not onsite, but can be contacted by phone and gives his permission. The OSOS <u>or</u> the responsible department supervisor may release the SUBCLEARANCE. The sign off on the SUBCLEARANCE should be, " ________________ for ___________ permission by phone".

4.9.2.2 If the Nuclear Operation SUBCLEARANCE HOLDER is not on site and cannot be contacted the OSOS <u>and</u> responsible department supervisor shall complete and both sign Figure 9 and release the SUBCLEARANCE if stated conditions are met. The sign off on the SUBCLEARANCE should be "___________ for ___________ by Figure 9".

4.9.2.3 If Figure 9 conditions are not met the General Manager, Plant Manager or Plant Support Manager shall be contacted for permission and Figure 9 so noted. The sign off on the SUBCLEARANCE" should be ____________ by permission of ____________", if permission is granted by phone. If the Manager signs the release in person his name is sufficient.

4.9.2.4 If the Construction SUBCLEARANCE HOLDER cannot be contacted, the Construction Duty Officer shall be contacted. He should call the respective discipline manager and together complete Figure 9. If all question are answered yes both should sign approval to release the CLEARANCE.

This approval may be by telecon provided adequate answers can be obtained by phone and the duty officer and discipline manager sign figure 9 the next working day.

4.9.2.5 If Figure 9 for construction cannot be completed in the affirmation, the Unit II Field Construction Manager or the Project Construction Manager shall be contacted for permission. The sign off on the SUBCLEARANCE should be "____________ by permission of ____________" if granted by phone. If the Manager signs the release in person his name is sufficient.

4.9.2.6 If the SUBCLEARANCE HOLDER cannot by contacted, the person, requesting the CLEARANCE be released, will verify that all grounding devices, which the SUBCLEARANCE HOLDER or work crew may have installed, are removed.

4.9.3 The Shift Supervisor will provide a qualified operator to perform the CLEARANCE release.

4.9.4 The SS will determine mechanical and electrical equipment alignment requirements for that equipment contained within a clearance boundary. At the discretion of the Shift Supervisor, performance of a system line-up procedure for the affected portions of the system prior to returning the system to service, may be required.

4.9.5 The operator performing the CLEARANCE release shall:

a. Have the authorized CLEARANCE SHEET in his possession before removing any HOLD TAGS.

b. Remove the HOLD TAG or FUNCTIONAL TEST TAG as appropriate, position the equipment, and initial each step in the specified sequence. (perform the step labelled "1" first)

c. Sign and record date and time on the CLEARANCE SHEET when the release has been completed,

d. Return the CLEARANCE SHEET, HOLD TAGS and FUNCTIONAL TEST TAGS to the Shift Supervisor or TAGGING DESK OPERATOR. If the HOLD TAGS are contaminated with radioactive material, they shall be disposed of as radioactive trash and the Shift Supervisor or TAGGING DESK OPERATOR informed of their disposal.

4.9.6 The Shift Supervisor shall ensure INDEPENDENT VERIFICATION is performed when required. Upon completion the operator shall initial each CLEARANCE POINT as indicated and sign and date the space provided on the CLEARANCE SHEET.

4.9.7 The Shift Supervisor or TAGGING DESK OPERATOR will ensure that the released CLEARANCE is complete, destroy the HOLD and FUNCTIONAL TEST TAGS, and initial and date the UNIT CLEARANCE LOG in the space provided.

NOTE

Steps 4.9.8 and 4.9.9 are required only after receipt of the Unit Operating License.

4.9.8 If the system is Technical Specifications-related, the Shift Supervisor shall ensure a verification of operability is accomplished when the system is being returned to service following maintenance or testing. The Verification of Operability shall be entered in the Shift Supervisor's Log.

4.9.9 If the system is Technical Specifications-related, the Shift Supervisor shall provide explicit notification to the Reactor Operator that the system is in service. Such notification shall be recorded in the Unit Control Log.

4.9.10 The Shift Supervisor or TAGGING DESK OPERATOR will then submit the released CLEARANCE SHEET with any attachments to the Shift Clerk for routing to Document Control.

4.10 CAUTION TAGS

4.10.1 The Yellow Caution tags (Figure 11) may be attached to a switch, component, or piece of equipment to provide cautions related to operating the switch, component or equipment, i.e. seal water is isolated because of excessive leak[illegible] open it prior to starting pump.

4.10.2 Caution tag[illegible] the purpose of protecting the process and [illegible]nly. Caution tags are not used for the pro[illegible]ersonnel.

4.10.3 The content of [illegible] should be presented in clear and conc[illegible] large easy to read print.

4.10.4 Each Caution tag is [illegible]signed [illegible] number consisting of: Unit Number, Year, and the next sequential number from the Caution Tag Log (Figure 10). The equipment number and/or panel number will be placed on the Caution Tag and the Log.

4.10.5 The special instructions from the Caution Tag should be recorded in the remarks section of the Caution Log.

4.10.6 The SS is responsible for ensuring the Caution Tag is accurate and does not adversely impact the operation of other systems, components, or equipment.

4.10.7 Caution Tags are valid only when signed by a SS or higher Operations management. The SS approval will be obtained before removal of a Caution Tag.

4.10.8 Operations personnel removing the Caution tag will return the tag to the SS or Tagging Desk Operator. If the Caution tag is contaminated with radioactive material it will be disposed of as radioactive trash. The SS or Tagging Desk Operator will be informed of its disposal.

4.10.9 The SS or Tagging Desk Operator will ensure that removed Caution Tags are destroyed.

4.11 PERFORMING QUARTERLY CHECKS

4.11.1 The Shift Supervisor should ensure that the QUARTERLY CHECKS are performed on EXTENDED ACTIVE CLEARANCES by the quarterly anniversary of the CLEARANCE installation date.

NOTE

QUARTERLY CHECKS in high radiation areas need not be conducted unless the Shift Supervisor deems the check necessary.

4.11.2 The Shift Supervisor or TAGGING DESK OPERATOR should ensure that all EXTENDED ACTIVE CLEARANCES are still required by plant conditions.

4.11.3 The operator performing the QUARTERLY CHECK shall:

a. Review the Clearance Index versus the Active Clearance Sheets to ensure that they agree.

b. Have the CLEARANCE SHEET in his possession.

c. Check that the equipment is still properly HOLD tagged, the HOLD TAG is legible, and the equipment is in the specified position.

d. Replace all missing or damaged HOLD TAGS.

e. Report abnormalities to the TAGGING DESK OPERATOR and the Shift Supervisor.

f. Return the CLEARANCE SHEET to the Shift Supervisor or TAGGING DESK OPERATOR.

g. Review the Caution Tag Log and perform a Quarterly Check of Caution Tags. The requirements of 4.11.3 c, d, and e above apply.

4.11.4 Upon completion of a QUARTERLY CHECK, the Shift Supervisor or TAGGING DESK OPERATOR should initial and date the space provided on the UNIT CLEARANCE LOG and return the CLEARANCE SHEET to the active CLEARANCE books.

5.0 REFERENCES

5.1 ANS-3.2/ANSI N18.7-1976, "Administrative controls and Quality Assurance for the Operational Phase of Nuclear Power Plants" (Subsection 5.2.6, Equipment Control).

5.2 GPC, Power Generation Department Procedure - GEN-2075.000 "Power Generation Clearance Procedure"

5.3 GPC, Operations Department, "Electric System Operation Procedure" ("The Red Book")

5.4 IE Bulletin 79-06A "Review of Operational Errors and System Misalignments Identified During the Three Mile Island Incident", Action 10.

5.5 0737, "Clarification of TMI Action Plan Requirements"

5.6 OP-203, Jan/1982 "INPO Good Practice Procedures For The Protection Of Employees Working On Electrical And Mechanical Components."

5.7 PROCEDURES

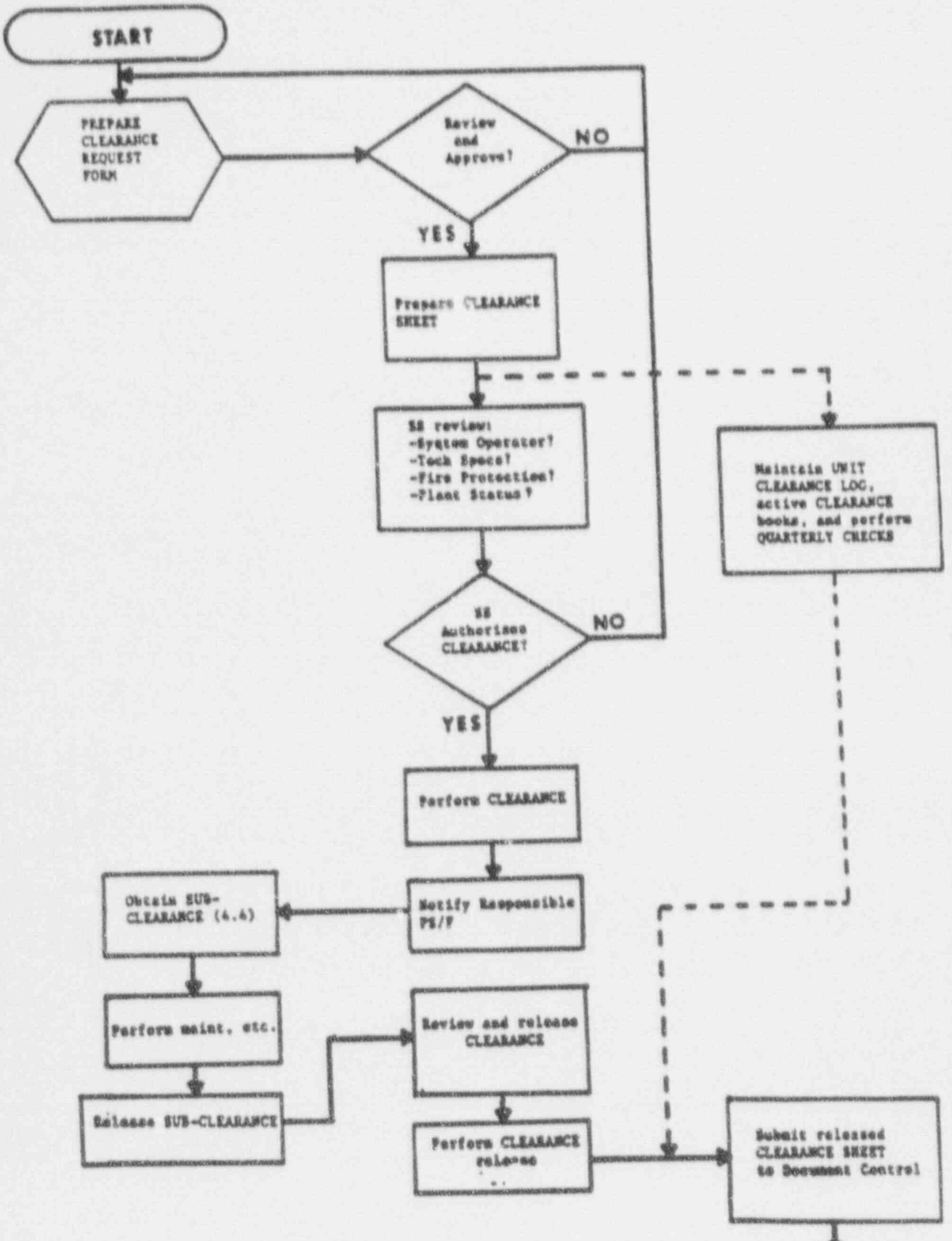
5.7.1 00306-C, "Temporary Jumper And Lifted Wire Control"

5.7.2 00308-C, "Independent Verification Policy"

5.7.3 13435-C, "Circuit Breaker Racking Procedure"

5.7.4 20429-C, "Short Term Documentation Of Temporary Jumper And Lifted Wire Control"

END OF PROCEDURE TEXT



FLOW CHART
OBTAINING AND RELEASING CLEARANCES

EXAMPLES OF TYPICAL HOLD TAGS

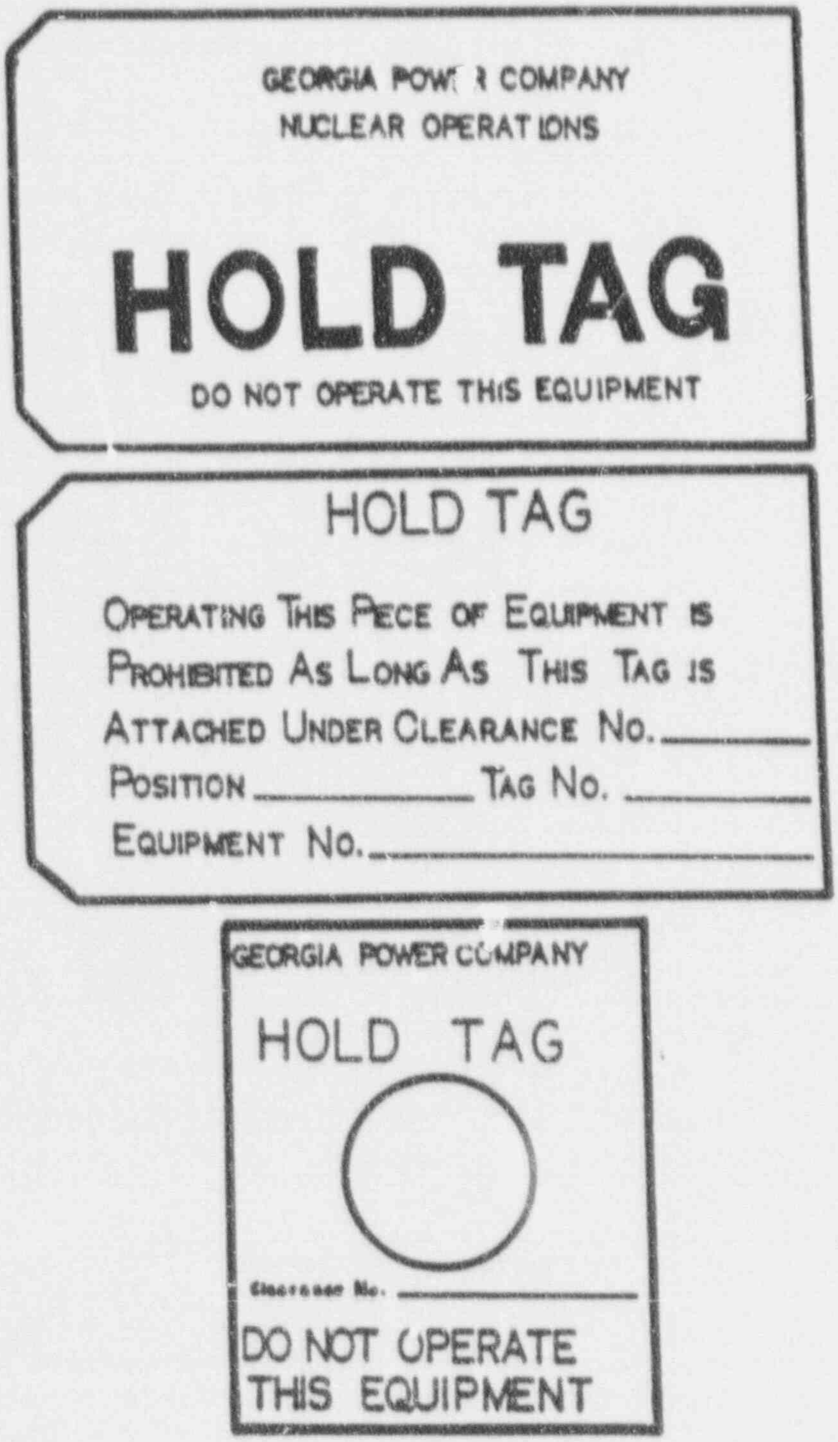


Figure 1

CLEARANCE REQUEST FORM

Description of Equipment/System: ______________________ Number: ______________

Reason For Clearance: ____

____

Estimated Outage Time: ____________ Work Order #: ______________

Requested Date/Time: _____ / _____ Needed Date/Time: _____ / _____

Requested by: ______________________ Extension: ____________

Recommended Clearance Points

Equipment	Position	Equipment	Position
1.		11.	
2.		12.	
3.		13.	
4.		14.	
5.		15.	
6.		16.	
7.		17.	
8.		18.	
9.		19.	
10.		20.	

Reference Drawings

P&ID: ____________ One-Line: ____________ Other: ______________

Figure 2

CLEARANCE SHEET CLEARANCE #______________

Equipment/System/Number: ______________________________

Reason For Clearance: ______________________________

Estimated Outage Time: ______________ Work Order #: ______________

Requested Date/Time: ______/______ Needed Date/Time: ______/______

Requested by: ______________________ Extension: ______________

Involves Tech. Spec. or Safety-Related Item: No___ Yes___

Locked Valves: No___ Yes___ Prepared By ______________

Fire Protection Impaired No___ Yes___ Reviewed By ______________

Authorized by: ______________ Date: ______________ Time: ______________

Installed by: ______________ Date: ______________ Time: ______________

Verified by: ______________ Date: ______________ Time: ______________

SUBCLEARANCES

NAME Printed in first space Signature in second space PRINTED AND SIGNATURE	WORK DOC	EXT	DATE	TIME	GROUNDING DEVICES VERIFIED REMOVED AND SUBCLEARANCE RELEASED BY: SIGNATURE	DATE	TIME
1.							
2.							
3.							
4.							
5.							

Subclearance Continuation Sheet Attached?	Yes	NO

CLEARANCE REMOVAL:

Authorized by: ______________ Date: ______________ Time: ______________

Removed by: ______________ Date: ______________ Time: ______________

Verified by: ______________ Date: ______________ Time: ______________

FRONT
Figure 3a
(TYPICAL)

703445

Sheet ____ of ____

CLEARANCE #: ____________ REFERENCES ______________________________

PREPARED BY ____________

Equipment To be Cleared and Tagged.				Tags To Be Removed And Equipment Returned to Service as Specified.		
Tag No.	Equipment Name and Number	Position	Init/Init(1)	Rem. Seq.	Position	Init/Init(1)
			/			/
			/			/
			/			/
			/			/
			/			/
			/			/
			/			/
			/			/
			/			/
			/			/
			/			/
			/			/

COMMENTS: ______________________________

(1) Second Initials are for Independent Verification.

BACK
FIGURE 3b CLEARANCE SHEET
(TYPICAL)

Sheet ___ of ___

SUBCLEARANCES - CONTINUATION SHEET

CLEARANCE # ____________________

NAME Printed in First Space Signature in Second Space					GROUNDING DEVICES VERIFIED REMOVED AND SUBCLEARANCE RELEASED BY:		
PRINTED AND SIGNATURE	WORK DOC	EXT	DATE	TIME	SIGNATURE	DATE	TIME

Figure 3c

UNIT CLEARANCE LOG

UNIT _____

CLEARANCE NUMBER	DESCRIPTION OF CLEARED EQUIPMENT	MWO NO.	INSTALLED DATE/INIT	RELEASED DATE/INIT	QUARTERLY CHECK	QUARTERLY CHECK

Figure 4 (TYPICAL)

FUNCTIONAL TEST FORM

CLEARANCE # ________

EQUIPMENT TO BE TESTED ____

____

REQUESTED BY ____

REASON FOR TEST ________________ TEST DOCUMENT NO. ____________

CLEARANCE POINTS TO BE RELEASED

Tag No.	Equipment No.	Req'd. Pos.	Init.

CLEARANCE RESTORATION

Sequence	Pos.	Init.	Init.

SUBCLEARANCE RELEASE FOR TEST	TIME	DATE

CLEARANCE ALIGNMENT RESTORED	TIME	DATE

VERIFIED BY	TIME	DATE

TEST ALIGNMENT PERFORMED BY
____________ TIME ____ DATE ______

SHIFT SUPERVISOR PERMISSION TO PERFORM TEST
____________ TIME ____ DATE ______

Figure 5

PARTIAL RELEASE FORM

CLEARANCE #:________

HOLD TAG # TO BE RELEASED	
SUBCLEARANCE HOLDER APPROVAL	
SIGNATURE	DATE/TIME
SS APPROVAL:	DATE/TIME
PERFORMED BY:	DATE/TIME
VERIFIED BY:	DATE/TIME

HOLD TAG # TO BE RELEASED	
SUBCLEARANCE HOLDER APPROVAL	
SIGNATURE	DATE/TIME
SS APPROVAL:	DATE/TIME
PERFORMED BY:	DATE/TIME
VERIFIED BY:	DATE/TIME

Figure 6

QUALIFIED SUBCLEARANCE HOLDER LIST

DATE ____________________

DEPARTMENT ______________________________

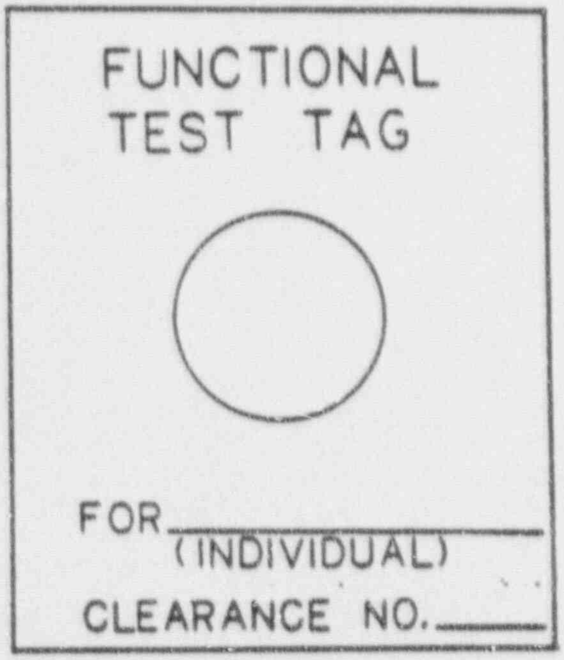
The following personnel are qualified by demonstrated ability and procedural knowledge to hold a subclearance per Procedure 00304-C.

NAME (PRINT)	SIGNATURE	PLT EXT/HOME PHONE #/BEEPER #

DEPARTMENT HEAD ______________________________

APPROVED BY:
MANAGER, OPERATIONS ______________________________

FIGURE 7



TYPICAL

FIGURE 8

SUBCLEARANCE (SC) RELEASE FORM

Clearance Number containing Subclearance to be released ________

SUBCLEARANCE HOLDER (SCH) Being Released ________

SUBCLEARANCE HOLDER (SCH) Work Phone No. ________

SUBCLEARANCE HOLDER (SCH) Home Phone No. ________

		CIRCLE	
1.	Was attempt made to contact SCH at home?	YES	NO
2.	Were applicable work orders and work document REVIEWED for completeness of work?	YES	NO
3.	Was equipment field verified safe to operate i.e., no equipment or personnel safety concerns?	YES	NO
4.	Has SCH's supervision been notified?	YES	NO
5.	Is it mandatory to release this CLEARANCE now? If yes, state why: ________	YES	NO
6.	Will action be taken to notify the SCH and CREW upon return to work that this SC has been released?	YES	NO

If all Six Questions are answered "YES", sign below and on the CLEARANCE to release the SUBCLEARANCE HOLDER.

*OSOS DATE/TIME #DEPARTMENT SUPV. DATE/TIME

DISTRIBUTION: 1) One copy attached to clearance

2) Original to Plant Manager

* Construction Duty Officer for construction subclearance holder.

\# Discipline manager for construction subclearance holder.

TYPICAL
FIGURE 9

CAUTION LOG

UNIT ______

CAUTION TAG NUMBER	EQUIPMENT/PANEL NUMBER	DATE INITIATED S.S. APPROVAL	CAUTION REMARKS	DATE REMOVED S.S. APPROVAL

FIGURE 10

CAUTION

DO NOT OPERATE THIS EQUIPMENT UNTIL SPECIAL INSTRUCTIONS ON REVERSE SIDE ARE THOROUGHLY UNDERSTOOD.

CLEARANCE NO. ______________

MPL NO. ______________

TAG NO. ______________

GEORGIA POWER COMPANY

NUCLEAR OPERATIONS

CAUTION

DO NOT OPERATE THIS EQUIPMENT UNTIL SPECIAL INSTRUCTIONS BELOW ARE THOROUGHLY UNDERSTOOD.

____

____

____

____

____

____

____

____

____

____

____

____

____

CAUTION

Clearance No. ______________

MPL No. ______________

DO NOT OPERATE THIS EQUIP UNTIL SPECIAL INSTRUCTIONS ON REVERSE SIDE ARE THOROUGHLY UNDERSTOOD.

Tag No. ________ Position ________

CAUTION

SPECIAL INSTRUCTIONS BELOW

____

____

____

____

GPC-NUCLEAR OPERATIONS

TYPICAL FIGURE 11

ADDITIONAL CLEARANCE POINT FORM

Clearance Number ______________________

Reason for addition ____

____

Clearance Points Requested

Equipment Number/Name Position	Equipment Number/Name Position
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________
______________________________	______________________________

SUBCLEARANCE HOLDER APPROVAL	DATE	TIME
______________________________	____	____
______________________________	____	____
______________________________	____	____
______________________________	____	____
______________________________	____	____
______________________________	____	____

SHIFT SUPERVISOR APPROVAL ________________ Date_____ Time _____

PERFORMED BY ________________ DATE ______ TIME ______

VERIFIED BY ________________ DATE ______ TIME ______

FIGURE 12

INFORMATION ONLY

PLANT VOGTLE UNITS 1 & 2
TECH SPEC INTERPRETATION 18 REVISION 3-30-90

TECH SPEC #: 3.4.1.4

QUESTION OR AREA NEEDING CLARIFICATION:

WHAT DOES "WITH REACTOR COOLANT LOOPS filled" MEAN?

INTERPRETATION:

We will consider loops filled when the RCS is filled and vented (ie S/G TUBES full) and level has been maintained >192' elevation. (See attached (W) Memo)

Approved By: [signature] 3-30-90
Manager Operations Date

xc: Manager Operations
Nuclear Safety & Compliance Manager
Engineering Support Manager
Plant Training & Emergency Prepardness Manager
Required Reading Book

FIGURE 2

CN-TA-88-71

FRSS/CWBS-460

Reference 2 ✓
M E [illegible] 3/28/88
JCR 5/5/88

FROM: NTSD Fluid, Radiation & Support Systems
WIN: 284-4317
DATE: February 16, 1987
SUBJECT: Boron Dilution Event Analysis - RCS Active Volumes

TO: J. C. Reck, WECE 4-09
Transient Analysis

cc: R. R. Etling
E. C. Arnold
R. A. Loose
File: DMW-281/2
MAH-281/2

P. A. Loftus, WECE 4-09
R. K. Stirzel
K. P. Slaby
P. A. Barilla
G. C. Sequin

References:

1-Letter FRSS/CWBS-455, 2-9-87.
2-Calculation FRSS/CWBS-C-093A, "Addendum A to FRSS/CWBS-C-093 (DMW, MAH)", J. E. Fix, 2-12-87.
3-Calculation FRSS/CWBS-C-093, "Boron Dilution Accident - RCS Active Volumes", J. E. Fix, 2-2-87.

In Reference 1, Fluids, Radiation, & Support Systems (FRSS) had transmitted the active mixing volume for use in the FSAR Boron Dilution Event analysis for several plants. This letter is a follow-up letter as FRSS has calculated and documented, in Reference 2, the active mixing volumes for Beaver Valley Unit #2 (DMW) and Seabrook Unit #1 (MAH). The active volumes include the volume of one full Reactor Coolant System loop (not including the upper head region of the reactor vessel) and one Residual Heat Removal train. The total active volumes for these plants are as follows:

DMW - Beaver Valley Unit #2	5013.9 cu.ft.
MAH - Seabrook Unit #1	5239.1 cu.ft.

Per your request, the volumes of those segments which composed the total active mixing volumes for those plants transmitted in Reference 1 are tabulated in the Attachment. If there are any questions, please feel free to contact the undersigned.

Jennifer E Fix
J. E. Fix, Engineer
Chemical, Waste, & BOP Systems

/plw
Attachment

CN-TA-88-71 36

page 1 of 1

Reference 2 ✓

ME 3/28/88

JCR 5/5/88

Attachment to FRSS/CWBS-460

Boron Dilution Event Analysis
RCS Active Volumes

Note: The volumetric units are cubic feet (ft^3).

(1) Segment	CGE	DMW	RGA/RHB KSR/KTR TWP/TXP	CAE CCE	CBE CDE	MAN GAE/GBE	SAP SCP	TBX	TCX
A	3	3	3	4	4	4	4	4	4
B	3733.7	3733.7	3643.5	4678.0	4678.0	4603.8	4646.1	4678.0	4721.3
(2)C	547.0	547.0	694.0	821.9	821.9	1019.9	1019.9	821.9	821.9
D	79.5	106.5	83.3	91.1	91.1	✓71.3 HL	71.3	79.5	79.5
E	935.0	1080.2	973.6	1036.0	936.0	✓973.6	973.6	1036.0	936.0
F	133.8	128.9	125.5	137.7	137.7	✓130.5	130.5	139.2	139.2
G	78.6	78.6	86.0	78.6	78.6	✓86.0 XL	86.0	78.6	78.6
H	89.3	119.7	89.9	98.6	98.6	✓80.8 CL	80.8	82.8	82.8
I	313.3	313.3	313.3	313.3	313.3	313.3	313.3	313.3	313.3
Total	4816.2	5013.9	4621.1	5611.4	5511.4	5239.1	5281.7	5585.5	5528.8

(1) Segment key:

A - # RCS loops
B - Reactor Vessel volume
C - Upper head and guide tube volumes
D - Hot Leg piping volume
E - S/G (Primary side) volume
F - Crossover Leg piping volume
G - Reactor Coolant Pump volume
H - Cold Leg piping volume
I - One RHR train volume

7542.2

5363.9

Jack/Jim,
This is Vogtle 1&2.
Steve DiT.

(2) The total volume is the sum of segments B and D through I. The volume of segment C is subtracted.

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

MAY 1 6 1991

MEMORANDUM FOR: Those on attached list

FROM: Gary Holahan, Deputy Director
Division of Systems Technology
Office of Nuclear Reactor Regulation

SUBJECT: MEETING MINUTES FOR SHUTDOWN AND LOW POWER ISSUES CONFERENCE HELD ON APRIL 30 - MAY 2, 1991

During the period April 30, 1991 to May 2, 1991, a conference on shutdown and low power issues was held in Rockville, Maryland. The purpose of the conference was to provide a forum for cognizant NRC personnel and personnel from associated national laboratories to discuss shutdown/low power issues and draw preliminary insights on the risks associated with these issues. The discussions were based on on-going evaluations and experience in the areas of shutdown and low power risks such as AEOD operating experience reviews, NRR site visits, Regional experience from inspections and operator licensing, and RES probabilistic risk assessments. The insights from the conference will be used to focus future program activities on the most safety significant issues.

The final agenda covered a broad range of topics and is provided as Enclosure 1. A composite list of participants over the three-day conference is provided in Enclosure 2. As a result of the discussions, preliminary insights were developed and are provided in Enclosure 3. The insights from the conference have been broadly categorized and are provided to you for review and comment. Your review should include any comments on the completeness of the list from conference discussions as well as any additional insights which you think are warranted as a result of reflecting on the subject of shutdown and low power issues.

All comments should be provided to Mark Caruso at (301) 492-3235 by May 24, 1991 in order to expeditiously proceed with near term program activities.

Gary M. Holahan

Gary Holahan, Deputy Director
Division of Systems Technology
Office of Nuclear Reactor Regulation

Enclosures:
As stated

cc: See next page

20014

DF03
1/1

MAY 1 6 1991

cc: Memorandum for those on attached list
Ralph Architzel (8D-1)
William Arciceri (INEL) (NL-007)
Jesse Arildsen (10D-24)
Jay Ball (9A-1)
Phil Brochman (RIII)
Allen Camp (Sandia)
Mark Caruso (8E-23)
Nilesh Chokshi (NLS-217)
Donald Copinger (ORNL)
Mike Cullingford (12G-18)
Mark Cunningham (NLS-372)
Kulin Desai (8E-23)
Paul Doyle (10D-22)
Bob Fitzpatrick (BNL)
Daniel Gallagher (SAIC)
Nanette Gilles (11E-22)
Anthony Gody, Jr. (13E-21)
Pete Habighorst (RI)
Gary Holahan (8E-2)
Kahtan Jabbour (9H-3)
Ronaldo Jenkins (7E-4)
Jim Knight (7E-4)
Lawrence Kokajko (13E-16)
Jack Kudrick (8D-1)
George Lanik (AEOD)
Bill Lazarus (RI)
Melvyn Leach (RIII)
Jim Lazevnick (7E-4)
Warren Lyon (8E-23)
Fred Manning (AEOD)
George Minarick (SAIC)
Robert Perch (8H-3)
Marie Pohida (10E-4)
William Raymond (RI)
Mark Reinhart (11E-24)
Howard Richings (8E-23)
Richard Robinson (NLS-372)
Faust Rosa (7E-4)
Bob Samworth (13E-21)
Susan Shankman (10D-24)
Warren Swenson (13E-4)
Norman Wagner (8D-1)
Len Ward (INEL) (NL-007)
Millard Wohl (11F-23)
Ashok Thadani (8E-2)
William Russell (12G-18)
Thomas Novak, AEOD (MNBB-3701)
Jack Rosenthal, AEOD (MNBB-9715)
Samuel Collins (Region IV)
Brian Sheron, RES (NLS-007)
NRR Division Directors
Central Files (P1-37)
SRXB R/F
PDR

ENCLOSURE 1

FINAL AGENDA

CONFERENCE ON SHUTDOWN AND LOW POWER ISSUES

DATE	SESSION	SUBJECT	PROPOSED DISCUSSION LEADER
4/30	8:15 AM	Opening Remarks	Gary Holahan, NRR
	8:30 AM	Presentation on RES PRA Studies	RES, BNL, SNL
	9:00 AM	Presentation on AEOD Review of Operating Experience	AEOD
	9:30 AM	PWR Loss of Decay Heat Removal and LOCA	Warren Lyon, NRR
4/30	Afternoon	ISLOCA	Sam Diab, NRR
		BWR Loss of Decay Heat Removal and LOCA	Tim Collins, NRR
5/1	Morning	Safety Assessment in Outage Planning and Management	Warren Lyon, NRR
5/1	Afternoon	Boron Dilution	Howard Richings, NRR
		BWR Fuel Misload	Howard Richings, NRR
		Heavy Loads/ Fuel Handling	Ralph Architzel, NRR
5/2	Morning	Availability of Electric Power	Jim Knight, NRR
		Containment Design and Closure Procedures	Jack Kudrick, NRR
5/2	Afternoon	Discussion of Overall Insights and Program Direction	Gary Holahan

ENCLOSURE 2

CONFERENCE ATTENDEES
SHUTDOWN AND LOW POWER ISSUES
APRIL 30 - MAY 2, 1991

NAME	ORGANIZATION
Ralph Architzel	NRR
William Arciceri	INEL
Jesse Arildsen	NRR
Jay Ball	NRR
Phil Brochman	Region III
Allen Camp	Sandia
Mark Caruso	NRR
Nilesh Chokshi	RES
Donald Copinger	ORNL
Mike Cullingford	NRR
Mark Cunningham	RES
Kulin Desai	NRR
Paul Doyle	NRR
Bob Fitzpatrick	BNL
Daniel Gallagher	SAIC
Nanette Gilles	NRR
Anthony Gody, Jr.	NRR
Pete Habighorst	Region I
Gary Holahan	NRR
Kahtan Jabbour	NRR
Ronaldo Jenkins	NRR
Jim Knight	NRR
Lawrence Kokajko	NRR
Jack Kudrick	NRR
George Lanik	AEOD
Bill Lazarus	Region I
Melvyn Leach	Region III
Jim Lazevnick	NRR
Warren Lyon	NRR
Fred Manning	AEOD
George Minarick	SAIC
Robert Perch	NRR
Marie Pohida	NRR
William Raymond	Region I
Mark Reinhart	NRR
Howard Richings	NRR
Richard Robinson	RES
Faust Rosa	NRR
Bob Samworth	NRR
Susan Shankman	NRR
Warren Swenson	NRR
Norman Wagner	NRR
Len Ward	INEL
Millard Wohl	NRR

INSIGHTS FROM CONFERENCE ON SHUTDOWN AND LOW POWER ISSUES

I. OUTAGE PLANNING AND CONTROL

A. GENERAL

* Outage planning and control may be the most significant elements of shutdown and low power risk.

* All utility personnel and programs are stressed during shutdown operations:

  - Operations
  - Engineering
  - Maintenance
  - Emergency Planning
  - Security
  - RAD Protection
  - Industrial Safety

* Contractor controls and training during shutdown is inconsistent (particularly for new individuals).

* In general, the emergency planning programs have not considered the special circumstances and problems encountered during shutdown (e.g., evacuation of workers, ability of TSC and others to deal with complex configurations).

* The effect of outage activities on operating units on the same site (e.g., shared systems, wrong unit).

* Forced outages get less planning but involve fewer and less complex activities.

* Rate of loss of a/c power to safety busses has been much greater during shutdown than during power operations.

* Fuel handling and heavy loads do not appear to be significant shutdown risk issues.

B OPERATIONS

* Operators have less control of activities and plant conditions during shutdown than during power operations.

* Entering and maintaining PWR mid-loop operation is a significant vulnerability.

* Operator actions are generally more necessary for events that occur during shutdown operation than for events initiating during power operation.

- Response procedures are weak.

  - Not specifically developed for shutdown operations.
  - Incomplete/not symptom oriented.

- For additional study - effects on plant staff of:

  - Overtime during outages
  - Changing shift rotations
  - Rapidly changing plant configuration
  - Accommodating to shutdown activities

- <u>Operator Training</u>

  - NRC operator exams generally do not cover shutdown conditions.
  - Simulators generally don't cover shutdown conditions.

- <u>Technical Specifications</u>

  - Plant modes in Tech Specs don't correspond to risk significant operating condition (e.g., PWR mid-loop, defueled).

  - Shutdown mode T/Ss can be confusing and don't consistently establish minimum requirements.

  - Some plant-specific TSs have no requirements on electrical power systems during shutdown.

  - STS typically only require one division of electrical power sources (1 EDG, 1 offsite, 1 battery, 1 ac distribution system, 1 DC bus, 2 vital ac buses from inverters) regardless of load requirements (Modes 4 and 5 for BWRs, Modes 5 and 6 for PWRs).

II. <u>HARDWARE/DESIGN</u>

- Shutdown instrumentation is not designed for shutdown conditions

  - Operators have reduced confidence in instruments
  - Availability problems
  - Inappropriate ranges
  - Instruments not well understood
  - Core temperature often not monitored

- Demands on equipment during various modes/configurations not always consistent with the design of the equipment (e.g., LPCI/RHR).

- BWRs generally have more water available during shutdown.

  - Injection sources
  - Higher level in vessel

* BWR Mark I and IIs have no "containment" capability during refueling (i.e., only limited "confinement" capability exists).
* PWR and BWR Mark III containments may be capable of containing shutdown accidents if appropriate plans and procedures are available.
* PWR containment integrity may be important during mid-loop operation.
* ECCS recirculation capability may be reduced or lost by intentional sump isolation (i.e., coverage to prevent debris entry) or by foreign material in containment during shutdown.
* PWR upper internals may inhibit water from entering the core from the refueling cavity.
* BWR loss of DHR is less significant than PWR loss of DHR.
* For additional study - Containment performance during accidents initiated from shutdown.
* For additional study - Role of secondary containment in shutdown accidents.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Title: BRIEFING ON SHUTDOWN RISK STATUS

Location: ROCKVILLE, MARYLAND

Date: JUNE 19, 1991

Pages: 71 PAGES

'91 JUN 26 P2:29

NEAL R. GROSS AND CO., INC.

COURT REPORTERS AND TRANSCRIBERS
1323 Rhode Island Avenue, Northwest
Washington, D.C. 20005
(202) 234-4433

9107020142

improvements in training and procedures. There is a general observation that both training and procedures have really historically been developed to deal with power operation, and this really runs the gamut from emergency procedures, use of simulators. Even NRC operator licensing program has really been focused on power operation and shutdown activities have not been really focused on and it's left those areas with less well-defined, less robust programs, and it's something that we think is important enough to look at.

The fourth item deals with technical specifications. One of them I think Bill mentioned earlier has to do with mode definitions. It became clear when both national laboratories began to put together their PRAs that the current mode definitions in technical specifications are really not detailed enough to identify the safety-significant conditions that the plant is in, the most obvious one being mid-loop operation for PWRs. That's not identified as a specific mode, doesn't have specific applicable limiting conditions for operation. It's really treated as either part of mode 5, cold shutdown, or mode 6, refueling, depending upon whether the head is tensioned or not.

But when the tech spec requirements were generated for mode 5 and 6 they really didn't envision the plant being in mid-loop operation. When the plant is in mode 6, refueling, we normally think of the refueling canal full of water, 23 feet of water and 300,000 or 400,000 gallons of water above the core, but in doing the PRAs it becomes clear that that typical condition is not really what always exists. When you're legally in mode 6, there's really a variety of conditions that the plant could be in.

In some of our discussions with utilities, it's become clear that when they plan an outage -- I remember one utility took mode 5 and divided it into 5A, 5B, 5C, because mode 5 didn't really establish unique conditions that set the real safety requirements for equipment and for activities. So, that's something that we think is important to look into.

The other part of the tech spec issue that turned up as important is the variability in what really is required in shutdown. What we find is, particularly in the older plants with custom tech specs, there are really minimal requirements on system availability during shutdown and refueling modes. There are a number of plants, for example, which have no requirements for AC power availability when the

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

DEC 17 1987

Docket No. 50-424
License No. NPF-68

Georgia Power Company
ATTN: Mr. James P. O'Reilly
Senior Vice President-Nuclear
Operations
P. O. Box 4545
Atlanta, GA 30302

Gentlemen:

SUBJECT: INSPECTION REPORT NO. 50-424/87-60

This refers to the Nuclear Regulatory Commission (NRC) inspection conducted by Messrs. J. F. Rogge, C. W. Burger, and R. J. Schepens on October 8 - November 20, 1987. The inspection included a review of activities authorized for your Vogtle facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed inspection report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Within the scope of the inspection, no violations or deviations were identified.

In accordance with Section 2.790 of the NRC's "Rules of Practice," Part 2, Title 10, Code of Federal Regulations, a copy of this letter and the enclosure will be placed in the NRC Public Document Room.

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

Sincerely,

Virgil L. Brownlee, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Enclosure:
NRC Inspection Report

cc w/encl: (See page 2)

8712280240

cc w/encl:
P. D. Rice, Vice President, Project Director
C. W. Hayes, Vogtle Quality Assurance Manager
G. Bockhold, Jr., General Manager, Nuclear Operations
L. Gucwa, Manager, Nuclear Safety and Licensing
J. A. Bailey, Project Licensing Manager
B. W. Churchill, Esq., Shaw, Pittman, Potts and Trowbridge
D. Kirkland, III, Counsel, Office of the Consumer's Utility Council
D. Feig, Georgians Against Nuclear Energy

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

Report No.: 50-424/87-60

Licensee: Georgia Power Company
P. O. Box 4545
Atlanta, GA 30302

Docket No.: 50-424

License No.: NPF-68

Facility Name: Vogtle 1

Inspection Conducted: October 8 - November 20, 1987

Inspectors: Peter A Balmain 12/16/87
for J. F. Rogge, Senior Resident Inspector — Date Signed

Peter A Balmain 12/16/87
for R. J. Schepens, Resident Inspector — Date Signed

Peter A Balmain 12/16/87
for C. W. Burger, Resident Inspector — Date Signed

Approved by: [illegible]
M. V. Sinkule, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed resident inspection in the following areas: plant operations, radiological controls, maintenance, surveillance, fire protection, security, and quality programs and administrative controls affecting quality.

Results: No violations or deviations were identified.

8712230251

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   G. Bockhold, Jr., General Manager Nuclear Operations
   *T. V. Greene, Plant Support Manager
   *R. M. Bellamy, Plant Manager
   *E. M. Dannemiller, Technical Assistant to General Manager
   C. C. Echert, Technical Assistant to Plant Manager
   *J. E. Swartzwelder, Nuclear Safety & Compliance Manager
   *W. F. Kitchens, Manager Operations
   R. E. Lide, Engineering Support Supervisor
   *H. Varnadoe, Plant Engineering Supervisor
   *R. E. Spinnatu, ISEG Supervisor
   C. W. Hayes, Vogtle Quality Assurance Manager
   *G. R. Frederick, Quality Assurance Site Manager - Operations
   W. E. Mundy, Quality Assurance Audit Supervisor
   M. A. Griffis, Maintenance Superintendent
   *R. M. Odom, Plant Engineering Supervisor
   *C. L. Cross, Senior Regulatory Specialist
   S. F. Goff, Regulatory Specialist
   *A. L. Mosbaugh, Assistant Plant Support Manager
   H. M. Handfinger, Assistant Plant Support Manager
   F. R. Timmons, Nuclear Security Manager

   Other licensee employees contacted included craftsmen, technicians, supervision, engineers, operations, maintenance, chemistry, inspectors, and office personnel.

   *Attended Exit Interview

2. Exit Interviews (30703)

   The inspection scope and findings were summarized on November 20, 1987, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection results. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspector during this inspection. Region based NRC exit interviews were attended during the inspection period by a resident inspector.

3. Operational Safety Verification (71707)(93702)

The plant began this inspection period in Power Operation (Mode 1) at 100% power until October 9 when the unit was tripped to complete a portion of the startup testing program and commence a short outage. The outage proceeded without difficulty until the number 1 reactor coolant pump motor failed. As a result of the failed motor, Unit 1 restart was delayed approximately seven days. The unit entered Hot Standby (Mode 3) on October 27. Shortly after achieving Mode 3 the residual heat removal crosstie valve motor operator failed and the engineering walkdowns identified that the reactor vessel level instrument impingement plates were not installed. These two problems resulted in further startup delays. On October 31 the unit entered Startup (Mode 2) and achieved Mode 1 on November 1. The unit achieved 100% power on November 4. On November 5 the unit tripped on a turbine trip when a vibration sensor was bumped. The unit returned to Mode 1 on November 6 and achieved 100% on November 7. On November 9 the unit performed the 10% load swing startup test. On November 11 the unit tripped from 100% reactor power when the wrong test panel was used during the performance of a reactor trip breaker test. On November 12 the unit returned to Mode 1 and achieved 90% power. From November 12 through 17 the unit experienced secondary water chemistry problems which limited power and required the plugging of condenser tubes. On November 18 the unit was held at 98% power while engineering concerns in regard to exceeding the 3411 MWT limit were resolved. On November 19 the unit achieved 100% power. The plant experienced three ESF actuations; the Control Room Emergency Ventilation System on October 26 when a technician improperly reset the radiation monitors and on November 17 when RE-12116 spiked high, an auxiliary feedwater actuation on November 5 when an operator shut the discharge valve of the running condensate pump due to improper labeling, and a Containment Ventilation Isolation from RE-2565 on November 9 when the check source did not fully retract. A Notice of Unusual Event was reported on November 17 when power was lost to meteorological instruments.

a. Control Room Activities

Control Room tours and observations were performed to verify that facility operations were being safely conducted within regulatory requirements. These inspections consisted of one or more of the following attributes as appropriate at the time of the inspection.

- Proper Control Room staffing
- Control Room access and operator behavior
- Adherence to approved procedures for activities in progress

- Adherence to Technical Specification (TS) Limiting Conditions for Operations (LCO)
- Observance of instruments and recorder traces of safety related and important to safety systems for abnormalities
- Review of annunciators alarmed and action in progress to correct
- Control Board walkdowns
- Safety parameter display and the plant safety monitoring system operability status
- Discussions and interviews with the On-Shift Operations Supervisor, Shift Supervisor, Reactor Operators, and the Shift Technical Advisor to determine the plant status, plans and assess operator knowledge
- Review of the operator logs, unit log and shift turnover sheets

No violations or deviations were identified.

b. Facility Activities

Facility tours and observations were performed to assess the effectiveness of the administrative controls established by direct observation of plant activities, interviews and discussions with licensee personnel, independent verification of safety systems status and LCO's, licensee meetings and facility records. During these inspections the following objectives were achieved:

(1) Safety System Status (71710) - Confirmation of system operability was obtained by verification that flowpath valve alignment, control and power supply alignments, component conditions, and support systems for the accessible portions of the ESF trains were proper. The inaccessible portions are confirmed as availability permits. Additional in-depth inspection of the Auxiliary Feedwater System was performed to review the system lineup procedure with the plant drawings and as-built configurations, compare valve remote and local indications, and walkdown of hangers, supports, snubbers and electrical equipment interiors. The inspector verified that the lineup was in accordance with license requirements for system operability.

(2) Plant Housekeeping Conditions - Storage of material and components and cleanliness conditions of various areas throughout the facility were observed to determine whether safety and/or fire hazards existed.

(3) Fire Protection - Fire protection activities, staffing and equipment were observed to verify that fire brigade staffing was appropriate and that fire alarms, extinguishing equipment, actuating controls, fire fighting equipment, emergency equipment, and fire barriers were operable.

(4) Radiation Protection (71709) - Radiation protection activities, staffing and equipment were observed to verify proper program implementation. The inspection included review of the plant program effectiveness. Radiation work permits and personnel compliance were reviewed during the daily plant tours. Radiation Control Areas (RCAs) were observed to verify proper identification and implementation.

(5) Security (71881) - Security controls were observed to verify that security barriers were intact, guard forces were on duty, and access to the Protected Area (PA) was controlled in accordance with the facility security plan. Personnel within the PA were observed to verify proper display of badges and that personnel requiring escort were properly escorted. Personnel within vital areas were observed to ensure proper authorization for the area. Equipment operability and proper compensatory activities were verified on a periodic basis.

(6) Surveillance (61726)(61700) - Surveillance tests were observed to verify that approved procedures were being used; qualified personnel were conducting the tests; tests were adequate to verify equipment operability; calibrated equipment was utilized; and TS requirements were followed. The inspectors observed portions of the following surveillances and reviewed completed data against acceptance criteria:

Date	Surv. No.	Dept.	Title
11/3/87	14915-1	Ops	QPTR Special Condition Surveillance Log
11/4/87	14915-1	Ops	Control Rod Insertion Limits Special Condition Surv. Log
11/4/87	14205-1	Ops	Plant Emergency Signal Weekly Operability Test
11/4/87	14805-101	Ops	Quarterly, Train B RHR Pump & Check Valve Inservice Test
11/6/87	14808-102	Ops	Quarterly, Train B CCP & Check Valve Inservice Test
11/19/87	14030-1	Ops	Power Range Calorimetric Channel Calibration
11/20/87	14825-108	Ops	Quarterly, Train A AFW Valve Inservice Test

(7) Maintenance Activities (62703) - The inspector observed maintenance activities to verify that correct equipment clearances were in effect; work requests and fire prevention work permits, as required, were issued and being followed; quality control personnel were available for inspection activities as required; retesting and return of systems to

service was prompt and correct; TS requirements were being followed. The maintenance backlog was reviewed and noted as consisting of approximately 2,100 MWO's (i.e., both corrective and preventive) prior to the outage. Maintenance had scheduled 249 maintenance work orders to be worked during the outage. During the outage the inspector observed that maintenance had actually performed an additional 151 MWO's due to discovery items and 109 MWO's due to the forced outage on the reactor coolant pump motor in addition to the 249 MWO's planned for a total of 509 MWO's. At the completion of the outage the outage backlog had been reduced from 506 to 300 MWO's, however the total MWO backlog had increased slightly from 2,100 to 2,178 MWO's. The inspector either observed maintenance activities or reviewed completed maintenance work packages for the following maintenance activities:

MWO No.	Dept.	Work Description
1-87-02793	Elect. Maint.	Perform MOVATS Procedure and DCP VIE007
1-87-05326	Elect. Maint.	Investigate Problem With Open Indication Light Not Working
1-87-08736	Mech. Maint.	Implement Design Change Package To Pressurizer Level Transmitter LT-461
1-87-11815	Maint./Chem.	Condenser Waterbox B West Tube Leak Check & Plugging

(8) Outage Activities (71711) - The inspector observed portions of the outage activities to determine management effectiveness in conducting outages. While this was not a refueling outage it did demonstrate the licensee's ability to schedule, prepare, and execute the plan. As noted above, at the completion of the outage the outage backlog had been reduced from 506 to 300 MWO's. During the course of the outage teamwork was evident in surfacing new problems and achieving resolution to prevent a new critical path from developing. The planned critical path work involving the removal of the temporary steam strainers was achieved ahead of schedule. The outage work inside containment was performed with few difficulties. Two major items did occur which had severe schedule impact and resulted in a seven day restart delay. These items were the motor replacement on the number one reactor coolant pump and the failed motor on the RHR crosstie valve HV-8716B. Teamwork in resolving both problems resulted in a very coordinated repair effort. Unit recovery was delayed upon discovery that the impingement plates for RVLIS were not installed nor locatable, which required new pieces to be fabricated.

No violations or deviations were identified

4. Review of Licensee Reports (90712)(90713)(92700)

a. In-Office Review of Periodic and Special Reports

This inspection consists of reviewing the below listed reports to determine whether the information reported by the licensee is technically adequate and consistent with the inspector knowledge of the material contained within the report. Selected material within the report is questioned randomly to verify accuracy to provide a reasonable assurance that other NRC personnel have an appropriate document for their activities.

Monthly Operating Reports - The report dated October 8, 1987 was reviewed. The inspector had no significant comments regarding these reports.

b. Licensee Event Reports (LER's) and Deficiency Cards (DC's)

Licensee Event Reports (LER's) and Deficiency Cards (DC's) were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events which were reported pursuant to 10 CFR 50.72, were reviewed as they occurred to determine if the technical specifications and other regulatory requirements were satisfied. In-office review of LER's may result in further followup to verify that the stated corrective actions have been completed, or to identify violations in addition to those described in the LER. Each LER is reviewed for enforcement action in accordance with 10 CFR Part 2, Appendix C. Review of DC's was performed to maintain a realtime status of deficiencies, determine regulatory compliance, follow the licensee corrective actions, and assist as a basis for closure of the LER when reviewed. Due to the numerous DC's processed only those DC's which result in enforcement action or further inspector followup with the licensee at the end of the inspection are discussed as listed below. The LER's denoted with an asterisk indicates that reactive inspection occurred at the time of the event prior to receipt of the written report.

(1) Deficiency Card reviews:

DC 1-87-2616 "DS-416 Reactor Trip Breaker Inspections" This deficiency documents the results of the weld inspections. During the inspections the NRC resident and vendor branch inspectors were present. The results of the inspection were acceptable however the NRC recommended that the shafts be replaced in the long term. These inspections were performed to address the concerns as addressed in Information Notice No. 87-35.

DC 1-87-2708 "RVLIS Impingement Covers" On 10/23/87 the impingement cover plates for RVLIS tubing for 1-LX-1310 and 1-LX-1320 were not installed. In order to correct this problem new plates were fabricated and installed. This resulted in a delay in return to power.

DC 1-87-2733 "Control Room Isolation While Resetting Radiation Monitors" This DC describes an unplanned actuation on 10/26/87 when the radiation parameter resetting procedure did not call for blocking of the output. In addition poor communication between operators and the chemistry department was exhibited in that the status of the Control Room Ventilation being reset was not fully understood nor was the nature of work to be performed.

DC 1-87-2753,1-87-2766,1-87-2846 "Mode 3 Entry Performed without all requirements met" These deficiency cards documented three instances that the licensee identified after the unit entered Mode 3. The three cases were failure to perform IST testing on the A train AFW discharge check valve following maintenance, failure to have the Steam Driven AFW pump steam admission valves open, and failure to perform a functional test of the A train safety injection pump following changeout of the lubricant. Each instances had minimal impact as follows: the check valve tested satisfactorily, full secondary steam pressure had not been obtained to support the surveillance testing, and the safety injection pump was tested satisfactorily.

DC 1-87-2915 "Reactor Trip While Performing OSP 14701-1" This Reactor Trip resulted when the B train auto shunt trip test panel was used during the testing of the A train breaker. While the procedure directed the operator to the correct test panel no labeling was in place at the test panel to indicate that the wrong train was being utilized. During the performance of the undervoltage coil trip test no additional indication existed to indicate that the shunt coil had not been blocked. When the shunt coil trip test was executed the B train shunt coil energized and the B train reactor trip breaker opened. Since the A train SSPS was in test to support A train reactor trip breaker testing the control room operator had to insert a manual trip to open the A train reactor trip breaker and perform a manual start of the A train Auxiliary Feedwater Pump.

DC 1-87-2974 "Missed Surveillance" This deficiency occurred on November 16 when a room temperature surveillance was not performed due to the floor being painted. The operator NA'd the step which was later identified during a supervisor review and at that time it was noticed that the TS had been missed.

(2) The following LER's were reviewed and are ready for closure pending verification that the licensee's stated corrective actions have been completed.

(a) 50-424/87-05, Rev 0-4 "120V AC Voltage Transient Causes ESF Actuations" These LERs describe a plant condition where a voltage transient causes ESF actuations upon energization of the Safety System Sequencer Panel. The inspector noted to the licensee that the final supplemental LER was due on July 30, 1987. The licensee informed the inspector that the LER will be closed on January 1988 once the information is received from Westinghouse.

(b) 50-424/87-20, Rev 0 "ESF Actuation Caused by Excessive Leakage Through a Main Feedwater Regulating Valve" The inspector noted to the licensee that the final supplemental LER was due on July 10, 1987. The licensee informed the inspector that the LER will be closed once the final corrective action is performed. The LER states that further testing of valve 1HV-5139 will be performed when the unit is in Mode 3. The Licensee failed to accomplish this test during the outage but will do the test at the next forced outage or refueling. The final LER will be issued following the test.

(c) 50-424/87-56, Rev 0 "Technical Specification Not Met Due To Incomplete Vendor Software For Dose Calculations" This LER describes an event which occurred on September 16, 1987 when it was identified that the cumulative dose calculation program for gaseous releases to the atmosphere for radioiodines did not include isotope I-133 in the software package. The licensee identified this during a data review while preparing the semi-annual radioactive effluent release report. Corrective action includes revising the software and the performance of a functional testing. The inspector has no further questions regarding this report. The following is identified:

50-424/LIV87-60-01 "Failure To Implement an Appropriate Surveillance to determine cumulative dose contributions in accordance with the ODCM per TS 4.11.2.3 - LER 87-56"

(d) 50-424/87-58, Rev 0 "False Signal From Rad Monitor Leads To Control Room Isolation" This LER describes an event which occurred on September 21, 1987 when the control room isolation occurred due to a false high radiation signal from 1-RE-12116. While no violations resulted from this event the licensee has yet to specify the root cause of the failure in a supplemental report due December 15, 1987.

(3) The following LER's were reviewed and are considered closed.

(a) 50-424/87-01, Rev 0 "Incorrect Transmitter Circuit Board Leads to Missing a Required Flow Rate Estimation" This LER was reviewed in NRC Rpt 50-424/87-44 and required verification of the corrective actions. The inspector reviewed procedure 34226-C and the training attendance sheets. The following item is identified:

50-424/LIV87-60-02 "Failure to Perform required TS Surveillance to Verify compliance with TS 3.3.3.10 - LER87-01"

(b) *50-424/87-02, Rev 0 "Potential Failure of MSIV's to Close Following Small Steam Line Break" This LER was reviewed in NRC Rpt 50-424/87-44 and required verification of the corrective actions. The inspection reviewed the vendor qualification report dated 3-20-87. This report documents that the main steam isolation valves which were supplied can remain in the open position for approximately 1 hour while exposed to a 320 degree F environment and retain the capability of closing and stopping steam flow in the system. The inspector noted that the test configuration included the relief valve (4100 psi) and that the hydraulic pressure reached only 3950 psi during the test. DCR 87 VIE 0030 was also reviewed. No further corrective actions are required as a result of the test report.

(c) *50-424/87-03, Rev 0 "Restriction of Pipe Movement with Incorrect Penetration Sealant Material" This LER was reviewed in NRC Rpt 50-424/87-44 and corrective action was verified during the course of the event. The inspector has no further questions.

(d) *50-424/87-04, Rev 0 "Contai ent Isolation Actuations Caused by Faulty Circuit Board" This LER was reviewed in NRC Rpt 50-424/87-44. Corrective action was verified regarding the repair of the faulty circuit during the course of the event. The inspector verified that a new annunciator has been added and 17006-1 response procedure changed. In addition the inspector noted that the radiation monitors have been removed as an input to containment isolation.

(e) *50-424/87-06, Rev 0 "ESF Actuation of Auxiliary Feedwater Due to Inadvertent Trip of the Main Feedwater Pumps" This LER was reviewed in NRC Rpt 50-424/87-44 and corrective action was verified during the course of the event. The inspector notes that a further corrective action has been the practice of removing the control fuses to the actuation circuit for AFW. This practice has resulted in LER 87-36 when the wrong fuses were pulled.

(f) *50-424/87-07, Rev 0 "ESF Actuation Caused by Steam Generator Water Level"; *50-424/87-09, Rev 0 "ESF Actuation Caused by Adjustments to Steam Generator Level Control

Systems"; *50-424/87-10, Rev 0 "RPS Actuation Caused by Adjustments to Steam Generator Level Control Systems"; *50-424/87-12, Rev 0 "Reactor Trip Due to Feedwater Control Problems Following Generator/Turbine Trip"; *50-424/87-14, Rev 0 "Steam Generator High Level Results In Reactor Trip"; *50-424/87-18, Rev 0 "Reactor Trip Caused by Faulty Bistable Circuit Board"; *50-424/87-24, Rev 0 "Procedure Inadequacy Causes Auxiliary Feedwater Actuation"; *50-424/87-25, Rev 0 "Reactor Trip Due to Startup Test Procedure Inadequacy"; *50-424/87-27, Rev 0 "Reactor Trip Caused by Inadvertent Closure of MSIV During Maintenance"; *50-424/87-30, Rev 0 "Lightning Causes Reactor Trip Due to Incorrectly Grounded Current Transformer"; *50-424/87-31, Rev 0 "Auxiliary Feedwater System Actuation During Startup Test Due to Procedure Inadequacy"; *50-424/87-34, Rev 0 "Reactor Trip Due to Failure of Main Feedwater Pump Discharge Check Valve"; *50-424/87-35, Rev 0 "Faulty Main Feedwater Pump Turbine Hydraulic Tubing Connection Leads to Reactor Trip"; *50-424/87-36, Rev 0 "Auxiliary Feedwater Actuation Circuitry Inoperable Due to Personnel Error", *50-424/87-39, Rev 0 "Pressure Transmitter Failure Causes ESF Actuation on Steam Generator Hi-Hi Water Level"; *50-424/87-41, Rev 0 "Reactor Trip Due to Improperly Calibrated Field Current Transducers"; *50-424/87-50, Rev 0 "Reactor Trip Caused by Instrument Technician's Error".

These LERs were reviewed in NRC Rpt 50-424/87-38 and NRC Rpt 50-424/87-44 with corrective action verified during the course of the events. Additional NRC concerns were addressed in several management meetings regarding the control of Steam Generator water level. Improved system performance resulted from increased operator experience and additional system tuning.

(g) *50-424/87-11, Rev 0 "Trip due to Lo-Lo Steam Generator Level" This LER was reviewed in NRC Rpt 50-424/87-44. The inspector noted that the corrective actions included temporary markings on the site glass and an engineering evaluation to determine further correction action. The inspector questioned the final status of these two actions and was informed that no further actions were necessary.

(h) *50-424/87-13, Rev 0 "Feedwater System Valve Malfunctions Result in Reactor Trip" This LER was reviewed in NRC Rpt 50-424/87-44 and at the time of the event. MWO 1-87-4987 was reviewed to verify proper reassembly. LER 87-34 describes a repeat failure of the same check valve and describes further corrective action.

(i) *50-424/87-15, Rev 0 "Inadvertent Steam Dump Operation Results in ESF Actuation" This LER was reviewed in NRC Rpt 50-424/87-44 and at the time of the event. Training was verified regarding the connection of test racks. The inspector noted to the licensee that the LER implies that the steam header pressure control loop was tested after the event to ensure its proper operation was part of the corrective action, when in fact the only testing was as part of the power ascension test phase. The licensee has not been responsive in revising the LER.

(j) *50-424/87-19, Rev 0 'Control Room Isolation Due to Signal From Toxic Gas Monitors"; *50-424/87-28, Rev 0 "Control Room Isolations Caused by Spurious Signals From Toxic Gas Monitor" Procedure 24537-1 and 24538-1 were reviewed to verify that monthly calibration checks were implemented. It was noted that the licensee is not required to have operable monitors since chlorine is removed from the site. The licensee is pursuing a TS change to raise the setpoint from 2 to 5 ppm to eliminate spurious actuations and then return chlorine onsite

(k) 50-424/87-21, Rev 0 "Control Room Isolation Initiated by Radiation Monitor Loss of Power" The final corrective actions for this problem will be discussed along with the resolution of LER87-05.

(l) *50-424/87-23 Rev 0 "RHR System Minimum Flow Requirement Potentially Not Met Due to Partially Closed Valves" This LER was reviewed in NRC Rpt 50-424/87-31 and resulted in the identification of a Severity Level III Violation 50-424/87-31-02. Procedure 14460-1 was verified to have the changes and the preventive maintenance sheets indicate the calibration frequency to be every six months. The corrective MWOs were also reviewed.

(m) *50-424/87-32, Rev 0 "Operator Error Leads to a Reactor Trip on Source Range High Flux" Procedure 12003-1 was reviewed to verify the requirement for a ICRR plot and a reactor engineer. Procedure 14940-1 was reviewed for to verify incorporation of correct boron worth and that the procedure will be performed by a reactor engineer. The training plan and simulator changes were reviewed.

(n) *50-424/87-33, Rev 0 "Reactor Trip on Steam Generator Lo-Lo Level While Transferring Feedwater Flow" Procedure 12004-1 was reviewed to verify that the correct power levels were indicated for transferring from the Bypass Feedwater regulating valve to the Main Feedwater regulating valve.

(o) *50-424/87-37, Rev 0 "Failure to Meet Technical Specification Action Statement Due to Procedural Inadequacy" Procedure 00150-C was reviewed to verify the additional guidance was incorporated. The inspector interviewed the NSSS engineering supervisor to determine the results of the LLRT performed during the outage. The results indicated that while degradation was noted the valve was within the acceptance criteria. The inspector determined that no actual TS violation had occurred since the valve was inoperable due to the potential that the leakage was high. This event served in identifying a procedural system weakness.

(p) *50-424/87-38, Rev 0 "Manual Reactor Trips Due To Overly Conservative Annunciator Response Procedure" Procedure 17010-1 was reviewed to verify that the response procedure has been revised to place DRPI in the Data A or Data B to regain rod position indication prior to a manual trip.

(q) *50-424/87-42, Rev 0 "Boron Concentration Exceeds Tech. Spec. Limiting Condition of Operation Time Limit" The tickler sheet was reviewed to show the correct TS limits. The memorandum regarding surveillances was also reviewed. This item is identified as follows:

50-424/LIV87-60-03 "Failure to Adequately Perform required TS Surveillance to Verify compliance with TS 3.1.2.6.b - LER87-42"

(r) *50-424/87-43, Rev 0 "Improper Performance of Containment Pressure Surveillance Due to Personnel Error" Procedure 14000-1 was reviewed to verify that the computer point was included in the procedure. This item is identified as follows:

50-424/LIV87-60-04 "Failure to Adequately Perform required TS Surveillance to Verify compliance with TS 3.6.1.4 - LER87-43"

(s) 50-424/87-46, Rev 0 "Waste Gas Decay Tank Not Sampled Within Technical Specifications Time Limit" The memorandum regarding surveillances was reviewed. Corrective actions include the establishment of fixed time. This item was identified in NRC report 50-424/87-49 as an LIV.

(t) *50-424/87-57, Rev 1 "Procedure Deficiency Results in Failure to Trip Overtemperature Delta T Reactor Trip Bistable". This LER describes an event which occurred on August 8, 1987 when the shift failed to place one of four required bistables in trip. The error was identified on August 9, 1987 during a control panel walkdown. The root cause was a procedural deficiency in specifying the correct bistables to trip. The inspector noted that the failure mode consisted of the pressure instrument drifting high about 40 psi and not a total failure high. At the inspectors request engineering performed a calculation to show the effect that this pressure drift would have on the setpoint. This calculation showed that even with this error the setpoint was within the 6.6% total allowance. The procedure was reviewed and the corrective actions have been completed. The inspector also noted that the LER was submitted late due to an improper review of the deficiency card. Both items above represent violations of NRC requirements where the licensee has met the criteria for no citation. To track these items the following are identified:

50-424/LIV87-60-05 "Failure to Place the OTDT Trip Bistables in the Trip Condition per TS 3.3.1 Item 7 - LER 87-57" and 50-424/LIV87-60-06 "Failure to Submit an LER Within 30 Days After The Discovery of the Event per 10 CFR 50.73(a)(1) - LER 87-57"

5. Management Meetings (30302B)

On October 21, 1987, an enforcement conference was held to discuss the results of NRC report 50-424/87-56.

On November 9, 1987, a site tour was given to the Director, Office of Nuclear Reactor Regulation (NRR), Thomas Murley and the Associate Director for Inspection & Technical Assessment, Richard Starostecki by the resident inspectors. Following the tour, two meetings were conducted with the licensee. The first meeting was held with the Unit 1 operations personnel and the second meeting was held with the Unit 2 construction personnel.

On November 10, 1987, the fourth onsite meeting with the licensee was held regarding the performance of the unit.

A local sampling point is provided for verifying the solution concentration before transferring it out of the tank. The tank is provided with an agitator to improve mixing during batching operations and a steam jacket for heating the boric acid solution.

9.3.4.1.2.5.14 Chemical Mixing Tank. The chemical mixing tank is used primarily in the preparation of caustic solutions for pH control, hydrazine solution for oxygen scavenging, and chemicals for corrosion product oxidation during a refueling shutdown.

9.3.4.1.2.5.15 Chiller Surge Tank. The chiller surge tank handles the thermal expansion and contraction of the water in the chiller loop. The surge volume in the tank also acts as a thermal buffer for the chiller. In addition, this tank can provide a holdup should there be a leak in the chiller heat exchanger. The fluid level in the tank is monitored with level indication and high- and low-level alarms provided on the main control board.

9.3.4.1.2.5.16 Mixed Bed Demineralizers. Two flushable mixed bed demineralizers assist in maintaining reactor coolant purity. A lithium-form cation resin and hydroxyl-form anion resin are charged into the demineralizers. The anion resin is converted to the borate form in operation. Both types of resin remove fission and corrosion products. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream, except for cesium, yttrium, and molybdenum, by a minimum factor of 10.

Each demineralizer has more than sufficient capacity for one core cycle with 1 percent of the rated core thermal power being generated by defective fuel rods. One demineralizer is normally in service with the other in standby.

A temperature sensor monitors the temperature of the letdown flow downstream of the letdown heat exchanger. If the letdown temperature exceeds the maximum allowable resin operating temperature (approximately 140°F), a three-way valve is automatically actuated so that the flow bypasses the demineralizers. Temperature indication and high alarm are provided on the main control board. The air-operated three-way valve failure mode directs flow to the volume control tank.

GP-14649

Westinghouse Electric Corporation **Energy Systems**

Nuclear and Advanced Technology Division

Box 355
Pittsburgh Pennsylvania 15230-0355

November 14, 1989
NS-OPLS-OPL-I-89-553

Mr. C. K. McCoy
Vice President, Nuclear Vogtle Project
Georgia Power Company
P.O. Box 1295
Birmingham, Alabama 35201

VOGTLE ELECTRIC GENERATING PLANT
UNITS 1 AND 2
Boron Dilution Analyses in Modes 5b and 6

Dear Mr. McCoy:

Westinghouse has completed the analyses to support the addition of a non-borated chemical solution to the RCS during shutdown modes with the conservative assumption that the loops are not filled. This procedure results in a dilution of the RCS boron concentration and has been analyzed with respect to the boron dilution transient presented in FSAR 15.4.6. The attached safety evaluation (SECL 89-943) provides the bases for the conclusion that this modification does not involve an unreviewed safety question. Attachment A to the safety evaluation provides the recommended FSAR changes while Attachment B provides the recommended technical specification changes and the accompanying significant hazards evaluation.

Reanalysis of the boron dilution event was necessary since dilution in Modes 5b (cold shutdown, loops not filled) and 6 (refueling) had not been analyzed due to precluding such an event by verifying certain valves to be closed. The results demonstrate that the Standard Review Plan (SRP) acceptance criteria for fifteen minutes in Mode 5b and thirty minutes in Mode 6 for operator action time between the high flux at shutdown alarm and criticality are met.

In Mode 5b, assuming a nominal dilution flow rate of 3.5 gpm results in a calculated operator action time of 100.47 minutes. The maximum acceptable dilution flow rate for Mode 5b is calculated to be 23.1 gpm, which results in an operator action time of 15.22 minutes. For Mode 6, assuming a 3.5 gpm dilution flow rate results in an operator action time of 377.87 minutes and a maximum acceptable flow rate calculated as 44.2 gpm with a resulting 30.54 minutes for operator action.

Based upon these results, it is concluded that the chemical addition to the RCS during Modes 5b and 6 as defined above does not violate the licensing basis acceptance criteria for a boron dilution event.

Please take a few minutes to complete and return the attached quality survey form for this product. If you have any questions or comments, please contact the undersigned.

Very truly yours,

WESTINGHOUSE ELECTRIC CORPORATION

J. L. Tain

J. L. Tain, Manager
Southern Company Projects

S DiTommaso

S. DiTommaso/
Attachments

cc: C. K. McCoy 1L, 1A
J. A. Bailey 1L, 1A
NORMS (Vogtle Site) 1L, 1A
G. L. Greenwood 1L, 1A
G. Bockhold, Jr. 1L, 1A
P. D. Rushton 1L, 1A
R. Odom 1L, 1A (Vogtle Site)
J. Aufdenkampe 1L, 1A (Vogtle Site)
J. Stringfellow 1L, 1A

SECL 89-943
Customer Reference No(s).
ELV-00930
Westinghouse Reference No(s).
AT-76510

WESTINGHOUSE NUCLEAR SAFETY
SAFETY EVALUATION CHECK LIST

1) NUCLEAR PLANT(S) : Vogtle Units 1 and 2

2) SUBJECT (TITLE): Periodic Opening of CVCS Valves in Modes 5 and 6 for Chemistry Control

3) The written safety evaluation of the revised procedure, design change or modification required by 10CFR50.59 (b) has been prepared to the extent required and is attached. If a safety evaluation is not required or is incomplete for any reason, explain on Page 2.
Parts A and B of this Safety Evaluation Check List are to be completed only on the basis of the safety evaluation performed.

CHECK LIST - PART A 10CFR50.59(a)(1)

(3.1) Yes_X_ No___ A change to the plant as described in the FSAR?
(3.2) Yes_X_ No___ A change to procedures as described in the FSAR?
(3.3) Yes___ No_X_ A test or experiment not described in the FSAR?
(3.4) Yes_X_ No___ A change to the plant technical specifications? (See note on Page 2.)

4) CHECK LIST - Part B 10CFR50.59(a)(2) (Justification for Part B answers must be included on Page 2.)

(4.1) Yes___ No_X_ Will the probability of an accident previously evaluated in the FSAR be increased?
(4.2) Yes___ No_X_ Will the consequences of an accident previously evaluated in the FSAR be increased?
(4.3) Yes___ No_X_ May the possibility of an accident which is different than any already evaluated in the FSAR be created?
(4.4) Yes___ No_X_ Will the probability of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?
(4.5) Yes___ No_X_ Will the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR be increased?
(4.6) Yes___ No_X_ May the possibility of a malfunction of equipment important to safety different than any already evaluated in the FSAR be created?
(4.7) Yes___ No_X_ Will the margin of safety as defined in the bases to any technical specifications be reduced?

NOTES:

If the answers to any of the above questions are unknown, indicate under 5) REMARKS and explain below.

If the answers to any of the above questions in Part A 3.4 or Part B cannot be answered in the negative, based on the written safety evaluation, the change review would require an application for license amendment as required by 10CFR50.59(c) and submitted to the NRC pursuant to 10CFR50.90.

5) REMARKS:

The following summarizes the justification based upon the written safety evaluation[1], for answers given in Part A 3.4 and Part B of this safety evaluation check list:

The proposed modification involves periodic opening of valves 176 and 177 to allow for chemical addition for water chemistry control. The effects of this change are evaluated for boron dilution concerns. FSAR and technical specification changes to implement this change are included.

[1]Reference to documents containing written safety evaluation:

FOR FSAR UPDATE

Section: 15.4.6, 9.3.4 Pages: All, 9.3.4-7 Tables: 15.4.6-1 Figures: -

Reason for/Description of Change:

To accurately reflect the use of valves 176 and 177 for periodic opening which will allow for chemical addition for water chemistry control.

6) SAFETY EVALUATION APPROVAL LADDER:

6.1) Prepared by (Nuclear Safety): Steven M. DiTommaso Date: 11/14/89
S. M. DiTommaso

6.2) Nuclear Safety Group Manager: R. J. Sterdis Date: 11/14/89
R. J. Sterdis

A. D. Rickn 11/14/89
[illegible] 11/14/89

Vogtle Units 1 and 2

Safety Evaluation in Support of
Periodic Opening of CVCS Valves 176 and 177
for Controlled Chemical Addition in Modes 5b and 6

1.0 BACKGROUND

It is necessary during Modes 5b (loops not filled, cold shutdown) and 6 (refueling) to periodically adjust the RCS chemistry. To accomplish this, Georgia Power is proposing to add chemicals to the RCS via the reactor makeup water storage tank discharge path through the chemical mixing tank. Valves 176 and 177 in the CVCS must be opened in order for this addition path to be used. The extent of the chemical addition is estimated to be for no longer than 30 minutes at a time for a maximum of 10 times throughout the Mode 5b and 6 duration. The maximum flow rate through this line under any condition with the valves open is calculated to be less than 3.5 gpm, which is identified in FSAR 15.4.6.2.1.2 as Initiator 3 for a potential boron dilution path.

The injection of a non-borated solution into the RCS for chemistry control during shutdown modes results in a dilution of the core boron concentration. The current boron dilution analysis for Vogtle is presented in FSAR 15.4.6. Dilution flow paths have been identified for Modes 3, 4, and 5a (loops filled) configurations. The analyses are performed in accordance with NUREG-0800, Standard Review Plan (SRP) 15.4.6, to demonstrate that at least fifteen minutes is available, between the high flux at shutdown alarm and complete loss of shutdown margin (criticality), for operator action time to terminate the dilution flow. Therefore, boron dilution analyses have been performed which verify that the anticipated dilution flow rates will still permit adequate time for operator action in accordance with the acceptance criteria. NRC approval of this analysis is provided in NUREG-1137 Supplement 1, Vogtle Units 1 and 2 Safety Evaluation Report, Section 15.4.6. However, analyses do not exist for dilution flow in Modes 5b or 6. Instead, boron dilution is precluded by verifying that the possible dilution flow paths are closed and secured in position in accordance with Technical Specifications 3/4.4.1.4.2 and 3/4.9.1. In order to verify that chemical addition in Modes 5b and 6 will not violate the acceptance criteria, specific analyses were performed to demonstrate adequate operator action time is available. Note that the acceptance criteria identified in SRP 15.4.6 for Mode 6 boron dilution is thirty minutes for operator action time.

2.0 LICENSING APPROACH AND SCOPE

The purpose of this safety evaluation is to support the FSAR changes and evaluate the proposed change in accordance with the criteria specified in 10CFR 50.59 so that the basis for the conclusion that the chemical addition does not involve an unreviewed safety question is identified. The assumptions and criteria presented above have been used as the bases upon which the Modes 5b and 6 boron dilution analyses were performed. Such a change in plant operating procedures will be reflected in the FSAR as well as the technical specifications. Therefore, Attachment A to this safety evaluation identifies the recommended FSAR changes. As it has been determined that modifications to the technical specifications are required to implement this change, submittal to the NRC for review and approval is required. Attachment B constitutes the significant hazards evaluation in accordance with 10CFR 50.92 and the associated recommended technical specification changes.

During Mode 6, reactivity conditions of the RCS must be maintained at the most restrictive of the two: RCS boron concentration above 2000 ppm or a K_{eff} of 0.95 or less per Technical Specification 3.9.1. Technical Specification 3.1.1.2 controls variable shutdown margin in Mode 5. These boron requirements have not changed as a result of the Modes 5b and 6 boron dilution analyses. Rather, the analyses have been performed such that they adhere to and are in conformance with these existing requirements. Also, the Modes 5b and 6 analyses have assumed the operability of the high flux at shutdown alarm in these modes, with a flux multiplier alarm setpoint of 2.3. This setpoint is defined in Technical Specification Table 4.3-1 Note 9 and is consistent with the Modes 3, 4 and 5a analyses.

The scope of this evaluation will address the effect of the Modes 5b and 6 boron dilution event on each of the disciplines within Westinghouse cognizance as discussed in detail in the following section.

3.0 EVALUATIONS

3.1 Non-LOCA Accident Analyses

The injection of non-borated chemical solution into the RCS for coolant chemistry control results in a dilution of the core boron concentration. A prolonged and unmonitored addition of the non-borated solution can be postulated to eventually result in the complete loss of shutdown margin. The current boron dilution analysis for Vogtle is presented in FSAR Section 15.4.6. Dilution flow paths have been identified for Modes 3, 4, and 5a (loops filled) configurations. The analyses were performed in accordance with NUREG-0800, Standard Review Plan (SRP) 15.4.6, to demonstrate that at least 15 minutes is available, between an alarm and complete loss of shutdown margin, for operator action time to terminate the dilution flow. Per the FSAR, boron dilution in Modes 5b and 6 is currently administratively precluded by verifying that possible dilution flow paths are isolated and the appropriate valves are secured in position in accordance with Technical Specifications 3/4.4.1.4.2 and 3/4/.9.1. Therefore, calculation of operator action time in Modes 5b and 6 is not currently required for the FSAR.

Analysis of the boron dilution event for Mode 5b and 6 with a minimum cold drained reactor vessel volume was performed assuming a maximum dilution flow rate of 3.5 gpm to determine the minimum operator action time. This flow rate is the maximum that can be achieved via the proposed flow path under any operating condition. In addition to using the minimum cold drained reactor vessel volume, the active RCS volume was further minimized by making the following assumptions: only one residual heat removal train is in operation, miniflow and bypass lines are considered empty, and no reactor coolant loop volumes are assumed. Note that the analyses also assume the operability of the high flux at shutdown alarm such that the instrumentation reliably annunciates a neutron flux level which is 2.3 times greater than that occurring at the initiation of the boron dilution event.

The results of the analyses demonstrate that for a dilution flow rate of 3.5 gpm or less there is sufficient operator action time available to terminate the flow after the high flux at shutdown alarm. The SRP acceptance criteria of fifteen minutes in Mode 5b and thirty minutes in Mode 6 for minimum operator action time is met and exceeded. No other non-LOCA safety analysis assumptions, methods or results are affected by the proposed procedure.

3.2 Mechanical Equipment Evaluation

The addition of a non-borated solution to the RCS via the chemical mixing tank will be performed in order to adjust water chemistry within the current requirements. Also, since the boron requirements will not change, the proposed change will not involve the creation of a new chemical environment to which the components will be exposed. Therefore, the performance and qualification of mechanical equipment will not be affected as a result of this modification.

3.3 Fluid Systems Performance Evaluation

The two plant fluid systems involved with this change are the reactor makeup water system (RMWS, FSAR 9.2.7) and the chemical and volume control system (CVCS, FSAR 9.3.4).

The function of the RMWS to supply degassified and demineralized water to the RCS is not altered as a result of this modification. Also, the makeup water chemistry specifications are not changed, therefore the performance requirements and capacity of the RMWS will not be challenged or exceeded.

Similarly, the function of the CVCS to control RCS chemistry is not altered. The addition of chemicals to the RCS in Modes 5b and 6 via the RMWS is in accordance with the procedure for addition of chemicals to maintain water quality as already described in FSAR 9.3.4.1.2.2. Therefore, no new system alignments or performance criteria are imposed on the CVCS as a result of this change.

3.4 Instrumentation and Control Evaluation

The Mode 5b and 6 boron dilution analyses assume the operability of the high flux at shutdown alarm in these modes, which receives input from the source range neutron flux monitors. In order to assume the high flux at shutdown alarm, which indicates to the operator that manual action to terminate dilution flow is required, this function must be operable during Modes 5b and 6. Given that the high flux at shutdown alarm function is operable, the performance requirements for the equipment and channels to detect and alarm for an increasing flux condition are not changed for service in these modes. Qualification of the source range detectors remains valid as documented in FSAR Table 3.11.N.1-1. The flux multiplier setpoint for the alarm for all modes is consistent and remains at 2.3.

3.5 LOCA and LOCA-related Accident Evaluation

Chemical addition for water chemistry control in Modes 5b and 6 is not modelled in the LOCA and LOCA-related accidents. Since all applicable technical specifications for RCS boron concentration remain unchanged and will continue to be met by surveillance, there is no adverse effect on the following analyses and the conclusions presented in the FSAR remain bounding for small and large break LOCA, LOCA hydraulic forces, rod ejection mass releases, post-LOCA long term core cooling, steam generator tube rupture and hot leg switchover to prevent boron precipitation.

3.6 Containment Peak Pressure/Temperature Evaluation

Containment analyses are limiting for mass and energy releases as a result of a steam line break or large break LOCA. Due to the fact that there is no effect on steam line break or LOCA mass and energy releases as a result of this change, the conclusions and limiting cases presented in the FSAR remain bounding.

4.0 <u>CONCLUSION</u>

Using the analyses and evaluations presented above, the bases upon which specific responses to the questions presented in Section 4 of the Checklist can be addressed. The addition of a non-borated solution during Modes 5b and 6 does not involve an unreviewed safety question as determined in the following discussion.

1. This chemical addition procedure does not increase the probability of an accident previously evaluated in the FSAR. No new performance requirements or alignments are being imposed on the CVCS or RMWS such that any design criteria will be exceeded. The recommended chemistry guidelines will continue to be adhered to, precluding the creation of an adverse chemical environment which may prematurely affect component performance. This dilution flow path, although administratively

precluded in Modes 5b and 6, was previously considered for Modes 3, 4, 5 and 6 in Chapter 15 of the FSAR. The classification of the boron dilution event continues to be an ANS condition II incident, one of moderate frequency. Other boron dilution flow paths will continue to be precluded by the technical specifications.

2. The consequences of an accident previously evaluated in the FSAR are not increased due to this chemical addition procedure. The results presented in the FSAR for the Modes 3, 4 and 5a dilution events remain valid. Boron dilution as a result of chemical addition in Modes 5b and 6 will not create more severe dose consequences.

3. This chemical addition procedure does not create the possibility of an accident which is different than any already evaluated in the FSAR. Boron dilution configurations in Modes 5b and 6 have been previously considered and evaluated in the FSAR. The conclusion was to keep the flow paths isolated so that no dilution flow was possible. In order to support the chemical addition procedure, an alternative approach, which utilized specific analyses that are bounding for the injection path configuration, was used. The results indicate that the required operator action time is available, given the expected dilution flow rates. Therefore, the Modes 5b and 6 boron dilution analyses meet the Plant Vogtle licensing basis acceptance criteria for this event. Other boron dilution flow paths will continue to be precluded by the technical specifications.

4. This chemical addition procedure will not increase the probability of a malfunction of equipment important to safety. As stated previously, component and system performance will not be adversely affected and no new system alignments are required which will challenge the CVCS and RMWS design bases.

5. The chemical addition procedure will not increase the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR. The chemical addition procedure will not degrade any system performance such that its malfunction will adversely affect another transient. Therefore, no more severe dose consequences will result due to this procedure.

6. The chemical addition procedure will not create the possibility of a malfunction of equipment important to safety different than any already evaluated in the FSAR. All original design and performance criteria continue to be met for the CVCS and RMWS such that there is no new failure mode expected as a result of this procedure. The chemical addition procedure has not introduced a new limiting single failure for these systems.

7. The margin of safety in the plant licensing basis for boron dilution is defined as operator action time between the high flux at shutdown alarm and loss of shutdown margin (criticality). The high flux at shutdown alarm setpoint defined in Technical Specification Table 4.3-1 Note 9 is 2.3. For Mode 5b, the operator action acceptance criteria as defined in SRP 15.4.6 is fifteen minutes and for Mode 6 SRP 15.4.6 defines the acceptance criteria as thirty minutes. The analysis criteria is designed to provide sufficient time for the operator to mitigate the event and prevent the complete loss of shutdown margin. Prevention of the loss of shutdown margin ensures that all ANS Condition II criteria are met. Therefore, the margin of safety is not reduced.

It can therefore be concluded that the addition of a non-borated chemical mixture through the flow paths provided by valves 176 and 177 in the CVCS during Modes 5b and 6 does not involve an unreviewed safety question as defined in 10 CFR 50.59.

ATTACHMENT A

RECOMMENDED FSAR CHANGES

materials and water chemistry of borated water/stainless steel/zirconium/Inconel systems. In addition, lithium-7 is produced in the core region due to irradiation of the dissolved boron in the coolant.

The concentration of lithium-7 in the RCS is maintained within the range 0.2 to 2.5 ppm as lithium for pH control. (See table 5.2.3-3.) If the concentration exceeds this range, as it may during the early stages of a core cycle, the CVCS demineralizers are employed to remove excess lithium. Since the amount of lithium to be removed is small and its buildup can be readily calculated, the flow through the demineralizers is not required to be full letdown flow. If the concentration of lithium-7 is below the specified limits, lithium hydroxide can be introduced into the RCS via the charging flow. The solution is prepared in the laboratory and poured into the chemical mixing tank. Reactor makeup water is then used to flush the solution to the suction manifold of the charging pumps.

B. Oxygen Control

During plant startup from the cold condition, hydrazine is employed to scavenge oxygen. The hydrazine solution is introduced into the RCS in the manner described above for the pH control agent. Hydrazine is not normally employed except during startup from the cold shutdown state.

refueling and

During normal plant operation, hydrogen dissolved in the reactor coolant is used to control and scavenge oxygen produced by radiolysis of water in the core region. A sufficient partial pressure of hydrogen is maintained in the volume control tank such that the normal operating range of 30-40 cm^3 (STP) H_2/kg H_2O is obtained. A pressure control valve maintains a minimum pressure of 15 to 20 psig in the vapor space of the volume control tank. This valve can be adjusted to provide the correct equilibrium hydrogen concentration. Hydrogen is supplied from the hydrogen manifold in the auxiliary gas system.

C. Reactor Coolant Purification

Mixed bed demineralizers are provided in the letdown line to provide cleanup of the letdown flow. The demineralizers remove ionic corrosion products and

15.4.6 CHEMICAL AND VOLUME CONTROL SYSTEM MALFUNCTION THAT RESULTS IN A DECREASE IN THE BORON CONCENTRATION IN THE REACTOR COOLANT

15.4.6.1 Identification of Causes and Accident Description

Reactivity can be added to the core by feeding primary grade water into the reactor coolant system (RCS) via the chemical and volume control system (CVCS). Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water during normal charging to that in the RCS. The CVCS is designed to limit the potential rate of dilution to a value which, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

The opening of the primary water makeup control valve provides makeup to the RCS which can dilute the reactor coolant. Inadvertent dilution from this source can be readily terminated by closing the control valve. In order for makeup water to be added to the RCS at pressure, at least one charging pump must be running in addition to a reactor makeup water pump. Normally, only one primary grade water supply pump is operating while the other is on standby.

The boric acid from the boric acid tank is blended with primary grade water at the mixing tee, and the composition is determined by the preset flowrates of boric acid and primary grade water on the control board.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of the pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flowrates deviate from preset values as a result of system malfunction.

This event is classified as an American Nuclear Society Condition II incident (an incident of moderate frequency) as defined in subsection 15.0.1.

15.4.6.2 Analysis of Effects and Consequences

15.4.6.2.1 Method of Analysis

To cover all phases of the plant operation, boron dilution during refueling, startup, cold shutdown, hot standby, and power operation are considered in this analysis.

Insert A

15.4.6.2.1.1 Dilution During Refueling. ~~An uncontrolled boron dilution accident cannot occur during refueling. This accident is prevented by administrative controls which isolate the RCS from the potential source of unborated water.~~

~~Valves 175, 176, 177, and 183 in the CVCS will be locked closed or isolated by removal of control air or electrical supply during refueling operations. These valves will block the flow paths which could allow unborated makeup water to reach the RCS. Any makeup which is required during refueling will be borated water supplied from the refueling water storage tank by the low head safety injection pumps.~~

15.4.6.2.1.2 Dilution During Cold Shutdown, Hot Standby, and Hot Shutdown. An analysis was performed to evaluate boron dilution events during cold shutdown, hot shutdown, and hot standby. Failure modes and effects analysis, human error analysis, and event tree analysis were used to identify credible boron dilution initiators and to evaluate the plant response to these events. For the initiators identified, time intervals from alarm to loss of shutdown margin were calculated to determine the length of time available for operator response. These calculations depended on dilution flowrates, boron concentrations, and Reactor Coolant System volumes specific to the event and mode of operation. The technique modeled realistic plant conditions and responses, including both mechanical failure and human errors.

The analysis identified four events which were considered to be the most likely initiators:

1. Demineralizer outlet isolation valve open during resin flushing.

2. Valve 226 open following BTRS demineralizer flushing operation.

3. Failure to secure chemical addition.

4. Boric acid flow control valve (FV-110A) fails closed during make-up.

INSERT A

15.4.6.2.1.1 Dilution During Refueling. A very small amount of unborated chemical solution is allowed to enter the RCS for water chemistry quality control. The dilution flow path is provided by opening CVCS valves 176 and 177. The maximum flow rate possible through this flow path is less than 3.5 gpm which is approximately 3% of the limiting flow rate considered in the analysis for Modes 3, 4 and 5a. Any other chemical makeup solution which is required during refueling will be borated water supplied from the refueling water storage tank by the low head safety injection pumps.

Valves 175 and 183 in the CVCS will be locked closed or isolated by removal of control air or electrical supply during refueling operations. These valves will block additional flow paths which could allow unborated chemical makeup water in excess of 3.5 gpm to reach the RCS.

Insert B

5a

Initiator 4 was found to be the most limiting event for modes 3, 4, and 5. The parameters used in the calculation of time available for operator response are listed in table 15.4.6-1. Conservative values of boron worth (pcm/ppm), as a function of RCS boron concentration, were assumed in the analysis.

Since the active volumes considered are so small in cold shutdown with the reactor coolant loops drained, it was determined that the same valves locked out in refueling would need to be locked out in cold shutdown when the reactor coolant loops are drained (see paragraph 15.4.6.2.1.1).

15.4.6.2.1.3 <u>Dilution During Full Power Operation, Including Startup</u>.

15.4.6.2.1.3.1 Dilution During Startup. Conditions at startup require the reactor to have available at least 1.30-percent Δk/k shutdown margin. The maximum boron concentration required to meet this shutdown margin is conservatively estimated to be 1704 ppm (Unit 1), and 1692 ppm (Unit 2). The following conditions are assumed for an uncontrolled boron dilution during startup:

A. Dilution flow is assumed to be the combined capacity of the two primary water makeup pumps (approximately 242 gal/min).

B. A minimum water volume, 9757 ft^3 (Unit 1) and 9972 ft^3 (Unit 2) in the reactor coolant system is used. This volume corresponds to the active volume of the RCS minus the pressurizer volume.

15.4.6.2.1.3.2 Dilution During Power Operation. During power operation, the plant may be operated two ways, under manual operator control or under automatic T_{avg}/[illegible] control. While the plant is in manual control, the dilution [illegible]w is assumed to be a maximum of 242 gal/min, which is the combined capacity of the two primary water makeup pumps. While in automatic control, the dilution flow is limited by the maximum letdown flow (approximately 125 gal/min).

Conditions at power operation require the reactor to have available at least 1.30-percent Δk/k shutdown margin. The maximum boron concentration required to meet this shutdown margin is very conservatively estimated to be 1366 ppm (Unit 1) and 1704 ppm (Unit 2).

INSERT B

In Mode 5b (mid-loop operatio.), Initiator 3 was also considered to allow the addition of small amounts of unborated chemical solution into the RCS for water chemistry control. The maximum flow rate possible through this flow path is approximately 3% of that associated with the limiting flow path for Modes 3, 4 and 5a.

A minimum water volume of 9972.3 ft^3 in the RCS is used. This volume corresponds to the active volume of the RCS minus the pressurizer volume.

15.4.6.2.2 Results

The calculated sequence of events is shown ~~in table 15.4.1-1.~~ Insert C

~~15.4.6.2.2.1 Dilution During Refueling. Dilution during refueling cannot occur due to administrative controls. (See paragraph 15.4.6.2.1.1).~~

15.4.6.2.2.2 Dilution During Cold Shutdown. For dilution during cold shutdown, the Technical Specifications provide the required shutdown margin as a function of RCS boron concentration. The specified shutdown margin ensures that the operator has 15 min from the time of the high flux at shutdown alarm to the total loss of shutdown margin. Insert D

15.4.6.2.2.3 Dilution During Hot Standby and Hot Shutdown. For dilution during hot standby and hot shutdown, the Technical Specifications provide the required shutdown margin as a function of RCS boron concentration. The specified shutdown margin ensures that the operator has 15 min from the time of the high flux at shutdown alarm to the total loss of shutdown margin.

15.4.6.2.2.4 Dilution During Startup. In the event of an unplanned approach to criticality or dilution during power escalation while in the startup mode, the operator is alerted to an unplanned dilution by a reactor trip at the power range neutron flux high, low setpoint. After reactor trip there is at least 19.0 min (Unit 1), and 17.25 min (Unit 2) for operator action prior to loss of shutdown margin.

15.4.6.2.2.5 Dilution During Power Operation. During full-power operation with the reactor in manual control, the operator is alerted to an uncontrolled dilution by an overtemperature ΔT reactor trip. At least 16.9 min (Unit 1), and 16.5 min (Unit 2) are available from the trip for operator action prior to loss of shutdown margin.

INSERT C

Since the maximum flow rate associated with the available dilution flow paths in Mode 6 is very small, the total time from initiation of event to the eventual complete loss of shutdown margin is significantly large compared to the minimum required operator action time. Therefore, a considerable amount of time is available for the operator to initiate and terminate procedures for RCS water chemistry adjustments before potential loss of shutdown becomes a concern. Additionally, assuming the availability of one HFAS set at 2.3 times backround it is shown that the Technical Specification shutdown margin requirement for Mode 6 is sufficient to ensure that the operator has 30 minutes from the time of alarm to terminate the dilution before shutdown margin is lost.

INSERT D

due to Initiator 4 which is the limiting case for Mode 5a. The same condition as specified for Mode 6 in paragraph 15.4.6.2.2.1 applies for Mode 5b due to Initiator 3.

During full-power operation with the reactor in automatic control, the operator is alerted to an uncontrolled reactivity insertion by the rod insertion limit alarms. At least 36.8 min are available for operator action from the low-low rod insertion limit alarm until a loss of shutdown margin occurs.

15.4.6.3 Conclusions

The results presented above show that adequate time is available for the operator to manually terminate the source of dilution flow. Following termination of the dilution flow, the operator can initiate reboration to recover the shutdown margin.

VEGP-FSAR-15

TABLE 15.4.6-1

PARAMETERS[a]

Dilution Flowrates:

Initiator	Flowrate (gal/min)
1	63
2	100
3	3.5
4	110

Volumes:

Mode	Volume (ft^3)	Volume (gal)
3, 4	9972	74593
5a (filled)	5239	39188
5b (drained)*	3460	25880
6 (drained)	3460	25880

* Drained refers to the reactor vessel coolant level at the mid-plane of the nozzles.

a. See appendix 15B for reload cycles.

SECL 89-943

ATTACHMENT B

SIGNIFICANT HAZARDS EVALUATION
AND
RECOMMENDED TECHNICAL SPECIFICATION CHANGES

SECL 89-943

VOGTLE ELECTRIC GENERATING PLANT
NRC DOCKETS 50-424, 50-425
OPERATING LICENSES NPF-68, NPF-81
REVISION TO TECHNICAL SPECIFICATIONS
MODES 5B AND 6 BORON DILUTION

10 CFR 50.92 EVALUATION

Pursuant to 10 CFR 50.92, each application for amendment to an operating license must be reviewed to determine if the proposed change involves a significant hazards consideration. The amendment, as defined below, describing a non-borated chemical addition activity during Modes 5b and 6, has been reviewed and deemed not to involve significant hazards considerations. The basis for this determination follows.

Background

In order to provide for the capability to make non-borated chemical additions to the RCS during Modes 5b (loops not filled) and 6 (refueling) for proper water chemistry control, it was necessary to perform boron dilution analyses for the specific dilution path to be utilized in these modes. The injection of non-borated water into the RCS for chemistry control during shutdown modes results in a dilution of the RCS boron concentration. The current boron dilution analysis for Vogtle is presented in FSAR 15.4.6. Dilution flow paths during shutdown have been identified for Modes 3, 4, and 5a (loops filled) configurations. The analyses are performed in accordance with NUREG-0800, Standard Review Plan (SRP), Section 15.4.6 to demonstrate that at least fifteen minutes is available, between the high flux at shutdown alarm and complete loss of shutdown margin (criticality), for operator action time to terminate the dilution flow. Therefore, boron dilution analyses have been performed which verify that the anticipated dilution flow rates will still permit adequate time for operator action in accordance with the acceptance criteria. However, analyses do not exist for dilution flow in Modes 5b or 6. Instead, boron dilution is precluded by verifying that the possible dilution flow paths are closed and secured in position in accordance with Technical Specifications 3/4.4.1.4.2 and 3/4.9.1. In order to verify that chemical addition in Modes 5b and 6 will not violate the acceptance criteria, specific analyses were performed to demonstrate adequate operator action time is available. Note that the acceptance criteria identified in SRP 15.4.6 for Mode 6 boron dilution is 30 minutes for operator action time.

Analysis

A review of the accident analyses in the Vogtle FSAR has determined that the only transient which is affected by this chemical addition procedure is the boron dilution event. Since all applicable technical specifications for RCS boron concentrations will continue to be met by surveillance and the recommended RCS chemistry will not be changed, there is no adverse effect on any other accident analyses or system or component performance.

During Mode 6, reactivity conditions of the RCS must be maintained at the most restrictive of the two: RCS boron concentration above 2000 ppm or a K_{eff} of 0.95 or less per Technical Specification 3.9.1. Technical Specification 3.1.1.2 controls variable shutdown margin in Mode 5. These boron requirements have not changed as a result of the Modes 5b and 6 boron dilution analyses. Rather, the analyses have been performed such that they adhere to and are in conformance with these existing requirements. Also, the Modes 5b and 6 analyses have assumed the operability of the high flux at shutdown alarm in these modes, with a flux multiplier alarm setpoint of 2.3. This setpoint is defined in Technical Specification Table 4.3-1 Note 9 and is consistent with the Modes 3, 4 and 5a analyses.

The injection of unborated chemical solution into the RCS for coolant chemistry control results in a dilution of the core boron concentration. A prolonged and unmonitored addition of the unborated solution can be postulated to eventually result in the complete loss of shutdown margin. The current boron dilution analysis for Vogtle is presented in FSAR Section 15.4.6. Dilution flow paths have been identified for Modes 3, 4, and 5a (loops filled) configurations. The analyses were performed in accordance with NUREG-0800, Standard Review Plan (SRP) 15.4.6, to demonstrate that at least fifteen minutes is available, between an alarm and complete loss of shutdown margin, for operator action time to terminate the dilution flow. Per the FSAR, boron dilution in Modes 5b and 6 is currently administratively precluded by verifying that possible dilution flow paths are isolated and the appropriate valves are secured in position in accordance with Technical Specifications 3/4.4.1.4.2 and 3/4/.9.1. Therefore, calculation of operator action time in Modes 5b and 6 is not currently required for the FSAR.

Analysis of the boron dilution event for Mode 5b and 6 with a minimum cold drained reactor vessel volume was performed assuming a maximum dilution flow rate of 3.5 gpm to determine the minimum operator action time. This flow rate is the maximum that can be achieved via the proposed flow path under any operating condition. In addition to using the minimum cold drained reactor vessel volume, the active RCS volume was further minimized by making the following assumptions: only one residual heat removal train is in operation, miniflow and bypass lines are considered empty, and no reactor coolant loop volumes are assumed. ~~Note that~~ the analyses also assume the operability of the high flux at shutdown alarm such that the instrumentation ~~reliably~~ annunciates a neutron flux level which is 2.3 times greater than that occurring at the initiation of the boron dilution event.

The results of the analysis demonstrate that for a dilution flow rate of 3.5 gpm or less there is sufficient operator action time available to terminate the flow after the high flux at shutdown alarm. The SRP acceptance criteria of fifteen minutes in Mode 5b and thirty minutes in Mode 6 for minimum operator action time is met and exceeded. No other non-LOCA safety analysis assumptions, methods or results are affected by the proposed procedure.

Results

Based on the information presented above, the following conclusions can be reached with respect to 10 CFR 50.92.

1. This chemical addition procedure does not increase the probability of an accident previously evaluated in the FSAR. No new performance requirements or alignments are being imposed on the CVCS or RMWS such that any design criteria will be exceeded. The recommended chemistry guidelines will continue to be adhered to, precluding the creation of an adverse chemical environment which may prematurely affect component performance. This dilution flow path, although administratively precluded in Modes 5b and 6, was previously considered for Modes 3, 4, 5 and 6 in Chapter 15 of the FSAR. The classification of the boron dilution event continues to be an ANS condition II incident, one of moderate frequency. Other boron dilution flow paths will continue to be precluded by the technical specifications.

2. The consequences of an accident previously evaluated in the FSAR are not increased due to this chemical addition procedure. The results presented in the FSAR for the Modes 3, 4 and 5a dilution events remain valid. Boron dilution as a result of chemical addition in Modes 5b and 6 will not create more severe dose consequences.

3. This chemical addition procedure does not create the possibility of an accident which is different than any already evaluated in the FSAR. Boron dilution configurations in Modes 5b and 6 have been previously considered and evaluated in the FSAR. The conclusion was to keep the flow paths isolated so that no dilution flow was possible. In order to support the chemical addition procedure, an alternative approach, which utilized specific analyses that are bounding for the injection path configuration, was used. The results indicate that the required operator action time is available given the expected dilution flow rates. Therefore, the Modes 5b and 6 boron dilution analyses meet the Plant Vogtle licensing basis acceptance criteria for this event. Other boron dilution flow paths will continue to be precluded by the technical specifications.

4. The margin of safety in the plant licensing basis for boron dilution is defined as operator action time between the high flux at shutdown alarm and loss of shutdown margin (criticality). The high flux at shutdown alarm setpoint defined in Technical Specification Table 4.3-1 Note 9 is 2.3. For Mode 5b, the operator action acceptance criteria as defined in SRP 15.4.6 is fifteen minutes and for Mode 6 SRP 15.4.6 defines the acceptance criteria as thirty minutes. The analysis criteria is designed to provide sufficient time for the operator to mitigate the event and prevent the complete loss of shutdown margin. Prevention of the loss of shutdown margin ensures that all ANS Condition II criteria are met. Therefore, the margin of safety is not reduced.

Conclusion

Based upon the preceding analysis, it has been determined that the proposed change to the technical specifications does not involve a significant increase in the probability or consequences of an accident previously evaluated, create the possibility of a new or different kind of accident from any accident previously evaluated or involve a significant reduction in a margin of safety. Therefore, it is concluded that the proposed changes meet the requirements of 10 CFR 50.92 (c) and do not involve a significant hazards consideration.

4. The margin of safety in the plant licensing basis for boron dilution is defined as operator action time between the high flux at shutdown alarm and loss of shutdown margin (criticality). The high flux at shutdown alarm setpoint defined in Technical Specification Table 4.3-1 Note 9 is 2.3. For Mode 5b, the operator action acceptance criteria as defined in SRP 15.4.6 is fifteen minutes and for Mode 6 SRP 15.4.6 defines the acceptance criteria as thirty minutes. The analysis criteria is designed to provide sufficient time for the operator to mitigate the event and prevent the complete loss of shutdown margin. Prevention of the loss of shutdown margin ensures that all ANS Condition II criteria are met. Therefore, the margin of safety is not reduced.

Conclusion

Based upon the preceding analysis, it has been determined that the proposed change to the technical specifications does not involve a significant increase in the probability or consequences of an accident previously evaluated, create the possibility of a new or different kind of accident from any accident previously evaluated or involve a significant reduction in a margin of safety. Therefore, it is concluded that the proposed changes meet the requirements of 10 CFR 50.92 (c) and do not involve a significant hazards consideration.

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

February 20, 1990

Dockets Nos. 50-424
and 50-425

Mr. W. G. Hairston, III
Senior Vice President -
Nuclear Operations
Georgia Power Company
P.O. Box 1295
Birmingham, Alabama 35201

Dear Mr. Hairston:

SUBJECT: ISSUANCE OF AMENDMENT NO.28 TO FACILITY OPERATING LICENSE NPF-68 AND AMENDMENT NO. 9 TO FACILITY OPERATING LICENSE NPF-81 - VOGTLE ELECTRIC GENERATING PLANT, UNITS 1 AND 2 (TACs 75320/75321)

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 28 to Facility Operating License No. NPF-68 and Amendment No. 9 to Facility Operating License NPF-81 for the Vogtle Electric Generating Plant, Units 1 and 2. These amendments consist of changes to the Technical Specifications (TSs) in response to your application dated November 21, 1989.

The amendments enable non-borated chemical additions to be made to the Reactor Coolant System (RCS) under administrative control during Mode 5b (cold shutdown, loops not filled) and Mode 6 (refueling) using a flow path via the Reactor Makeup Water Storage Tank (RMWST).

A copy of the related Safety Evaluation is also enclosed. Notice of issuance of the amendments will be included in the Commission's biweekly Federal Register notice.

Sincerely,

Timothy A. Reed, Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 28 to NPF-68
2. Amendment No. 9 to NPF-81
3. Safety Evaluation

cc w/enclosures:
See next page

9003070204

cc:
Mr. J. A. Bailey
Manager - Licensing
Georgia Power Company
P.O. Box 1295
Birmingham, Alabama 35201

Bruce W. Churchill, Esq.
Shaw, Pittman, Potts and Trowbridge
2300 N Street, N.W.
Washington, D.C. 20037

Mr. G. Bockhold, Jr.
General Manager, Vogtle Electric
Generating Plant
P.O. Box 1600
Waynesboro, Georgia 30830

Regional Administrator, Region II
U.S. Nuclear Regulatory Commission
101 Marietta Street, N.W., Suite 2900
Atlanta, Georgia 30323

Office of the County Commissioner
Burke County Commission
Waynesboro, Georgia 30830

Office of Planning and Budget
Room 615B
270 Washington Street, S.W.
Atlanta, Georgia 30334

Mr. C. K. McCoy
Vice Presient - Nuclear, Vogtle Project
Georgia Power Company
P.O. Box 1295
Birmingham, Alabama 35201

Resident Inspector
Nuclear Regulatory Commission
P.O. Box 572
Waynesboro, Georgia 30830

James E. Joiner, Esq.
Troutmen, Sanders, Lockerman,
& Ashmore
1400 Candler Building
127 Peachtree Street, N.E.
Atlanta, Georgia 30303

Mr. R. P. McDonald
Executive Vice President -
Nuclear Operations
Georgia Power Company
P.O. Box 1295
Birmingham, Alabama 35201

Mr. J. Leonard Ledbetter, Director
Environmental Protection Division
Department of Natural Resources
205 Butler Street, S.E., Suite 1252
Atlanta, Georgia 30334

Attorney General
Law Department
132 Judicial Building
Atlanta, Georgia 30334

Mr. Alan R. Herdt, Chief
Project Branch #3
U.S. Nuclear Regulatory Commission
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

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

GEORGIA POWER COMPANY

OGLETHORPE POWER CORPORATION

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

CITY OF DALTON, GEORGIA

VOGTLE ELECTRIC GENERATING PLANT, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 28
License No. NPF-68

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Vogtle Electric Generating Plant, Unit 1 (the facility), Facility Operating License No. NPF-68 filed by the Georgia Power Company, acting for itself, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the licensees), dated November 21, 1989, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this license amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

9003070209

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Facility Operating License No. NPF-68 is hereby amended to read as follows:

   Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 28 , and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. GPC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

DBMatthews

David B. Matthews, Director
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification Changes

Date of Issuance: February 20, 1990

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

GEORGIA POWER COMPANY

OGLETHORPE POWER CORPORATION

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

CITY OF DALTON, GEORGIA

VOGTLE ELECTRIC GENERATING PLANT, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 9
License No. NPF-81

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment to the Vogtle Electric Generating Plant, Unit 2 (the facility), Facility Operating License No. NPF-81 filed by the Georgia Power Company, acting for itself, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the licensees), dated November 21, 1989, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this license amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Facility Operating License No. NPF-81 is hereby amended to read as follows:

   Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 9 , and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. GPC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

DBMatthews

David B. Matthews, Director
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification Changes

Date of Issuance: February 20, 1990

ATTACHMENT TO LICENSE AMENDMENT NO. 28

FACILITY OPERATING LICENSE NO. NPF-68

AND LICENSE AMENDMENT NO. 9

FACILITY OPERATING LICENSE NO. NPF-81

DOCKETS NOS. 50-424 AND 50-425

Replace the following pages of the Appendix "A" Technical Specifications with the enclosed pages. The revised pages are identified by Amendment number and contain vertical lines indicating the areas of change. The corresponding overleaf pages are also provided to maintain document completeness.

Amended Page	Overleaf Page
3/4 4-6	3/4 4-5
3/4 9-1	
B3/4 4-1	B3/4 4-2
B3/4 9-1	B3/4 9-2

REACTOR COOLANT SYSTEM

COLD SHUTDOWN - LOOPS FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.1 At least one residual heat removal (RHR) train shall be OPERABLE and in operation*, and either:

a. One additional RHR train shall be OPERABLE**, or

b. The secondary side water level of at least two steam generators shall be greater than 17% of wide range (LI-0501, LI-0502, LI-0503, LI-0504).

APPLICABILITY: MODE 5 with reactor coolant loops filled***.

ACTION:

a. With one of the RHR trains inoperable or with less than the required steam generator water level, immediately initiate corrective action to return the inoperable RHR train to OPERABLE status or restore the required steam generator water level as soon as possible.

b. W' h no RHR train in operation, suspend all operations involving a r uction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR train to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4.1.1 The secondary side water level of at least two steam generators when required shall be determined to be within limits at least once per 12 hours.

4.4.1.4.1.2 At least one RHR train shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

---

*The RHR pump may be deenergized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

**One RHR train may be inoperable for up to 2 hours for surveillance testing provided the other RHR train is OPERABLE and in operation.

***A reactor coolant pump shall not be started unless the secondary water temperature of each steam generator is less than 50°F above each of the Reactor Coolant System cold leg temperatures.

COLD SHUTDOWN - LOOPS NOT FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.2 Two residual heat removal (RHR) trains shall be OPERABLE* and at least one RHR train shall be in operation.** Reactor Makeup Water Storage Tank (RMWST) discharge valves (1208-U4-175, 1208-U4-176#, 1208-U4-177# and 1208-U4-183) shall be closed and secured in position.

APPLICABILITY: MODE 5 with reactor coolant loops not filled.

ACTION:

a. With less than the above required RHR trains OPERABLE, immediately initiate corrective action to return the required RHR trains to OPERABLE status as soon as possible.

b. With no RHR train in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required RHR train to operation.

c. With the Reactor Makeup Water Storage Tank (RMWST) discharge valves (1208-U4-175, 1208-U4-176#, 1208-U4-177#, and 1208-U4-183) not closed and secured in position, immediately close and secure in position the RMWST discharge valves.

SURVEILLANCE REQUIREMENTS

4.4.1.4.2.1 At least one RHR train shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

4.4.1.4.2.2 Valves 1208-U4-175, 1208-U4-176#, 1208-U4-177#, and 1208-U4-183 shall be verified closed and secured in position by mechanical stops at least once per 31 days.

*One RHR train may be inoperable for up to 2 hours for surveillance testing provided the other RHR train is OPERABLE and in operation.

**The RHR pump may be deenergized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

#RMWST discharge valves 1208-U4-176 and 1208-U4-177 may be open under administrative control provided the Reactor Coolant System is in compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.2 and the high flux at shutdown alarm is OPERABLE with a setpoint of 2.30 times background in accordance with Note 9 of Table 4.3-1.

3/4.9 REFUELING OPERATIONS

3/4.9.1 BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 The boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of the following reactivity conditions are met:

a. A K_{eff} of 0.95 or less, or

b. A boron concentration of greater than or equal to 2000 ppm.

Additionally, valves 1208-U4-175, 1208-U4-177#, 1208-U4-183, and 1208-U4-176# shall be closed and secured in position.

APPLICABILITY: MODE 6.

ACTION:

a. With the requirements of a. and b. above not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to 30 gpm of a solution containing greater than or equal to 7000 ppm boron or its equivalent until K_{eff} is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to 2000 ppm, whichever is the more restrictive.

b. With valves 1208-U4-175, 1208-U4-177#, 1208-U4-183, and 1208-U4-176# not closed and secured in position, immediately close and secure in position.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The boron concentration of the Reactor Coolant System and the refueling canal shall be determined by chemical analysis at least once per 72 hours.

4.9.1.2 Valves 1208-U4-175, 1208-U4-177#, 1208-U4-183, and 1208-U4-176# shall be verified closed and secured in position by mechanical stops at least once per 31 days.

#RMWST discharge valves 1208-U4-176 and 1208-U4-177 may be open under administrative control provided the Reactor Coolant System is in compliance with the requirements of Specification 3.9.1 and the high flux at shutdown alarm is OPERABLE with a setpoint of 2.30 times background. For the purpose of this Specification, the high flux at shutdown alarm will be demonstrated OPERABLE pursuant to Specification 4.9.2.

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with all reactor coolant loops in operation and maintain DNBR above 1.30 during all normal operations and anticipated transients. In MODES 1 and 2 with one reactor coolant loop not in operation this specification requires that the plant be in at least HOT STANDBY within 6 hours.

In MODE 3, two reactor coolant loops provide sufficient heat removal capability for removing core decay heat even in the event of a bank withdrawal accident; however, a single reactor coolant loop provides sufficient heat removal capacity if a bank withdrawal accident can be prevented, i.e., by opening the Reactor Trip System breakers.

In MODE 4, and in MODE 5 with reactor coolant loops filled, a single reactor coolant loop or RHR train provides sufficient heat removal capability for removing decay heat; but single failure considerations require that at least two trains/loops (either RHR or RCS) be OPERABLE.

In MODE 5 with reactor coolant loops not filled, a single RHR train provides sufficient heat removal capability for removing decay heat; but single failure considerations, and the unavailability of the steam generators as a heat removing component, require that at least two RHR trains be OPERABLE. The locking closed of the required valves, except valves 1208-U4-176 and 1208-U4-177 for short periods of time to maintain chemistry control, in Mode 5 (with the loops not filled) precludes the possibility of uncontrolled boron dilution of the filled portion of the Reactor Coolant System. These actions prevent flow to the RCS of unborated water in excess of that analyzed. These limitations are consistent with the initial conditions assumed for the boron dilution accident in the safety analysis.

The operation of one reactor coolant pump (RCP) or one RHR pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reduction will, therefore, be within the capability of operator recognition and control.

The restrictions on starting an RCP with one or more RCS cold legs less than or equal to 350°F are provided to prevent RCS pressure transients, caused by energy additions from the Secondary Coolant System, which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by restricting starting of the RCPs to when the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures.

3/4.4.2 SAFETY VALVES

The pressurizer Code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 420,000 lbs per hour of saturated steam at the valve Setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an operating RHR train, connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization. In addition, the Cold Overpressure Protection System provides a diverse means of protection against RCS overpressurization at low temperatures.

During operation, all pressurizer Code safety valves must be OPERABLE to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss-of-load assuming no Reactor trip until the first Reactor Trip System Trip Setpoint is reached (i.e., no credit is taken for a direct Reactor trip on the loss-of-load) and also assuming no operation of the power-operated relief valves or steam dump valves.

During shutdown conditions in Mode 5 only one pressurizer code safety is required for overpressure protection. In lieu of an actual operable code safety valve an unisolated and unsealed vent pathway (i.e. a direct unimpaired opening) of equivalent size can be taken as synonymous with an OPERABLE code safety.

Demonstration of the safety valves' lift settings will occur only during shutdown and will be performed in accordance with the provisions of Section XI of the ASME Boiler and Pressure Code.

3/4.4.3 PRESSURIZER

The 12-hour periodic surveillance is sufficient to ensure that the parameter is restored to within its limit following expected transient operation. The maximum water volume ensures that a steam bubble is formed and thus the RCS is not a hydraulically solid system. The requirement that a minimum number of pressurizer heaters be OPERABLE enhances the capability of the plant to control Reactor Coolant System pressure and establish natural circulation.

BASES

3/4.9.1 BORON CONCENTRATION

The limitations on reactivity conditions during REFUELING ensure that: (1) the reactor will remain subcritical during CORE ALTERATIONS, and (2) a uniform boron concentration is maintained for reactivity control in the water volume having direct access to the reactor vessel. The locking closed of the required valves, except valves 1208-U4-176 and 1208-U4-177 for short periods of time to maintain chemistry control, during refueling operations precludes the possibility of uncontrolled boron dilution of the filled portions of the Reactor Coolant System. These actions prevent flow to the RCS of unborated water in excess of that analyzed. These limitations are consistent with the initial conditions assumed for the Boron Dilution Accident in the safety analysis. The Boron concentration value of 2000 ppm or greater ensures a K_{eff} of 0.95 or less and includes a conservative allowance for calculational uncertainties of 100 ppm of boron.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of the Source Range Neutron Flux Monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core.

3/4.9.3 DECAY TIME

The minimum requirement for reactor subcriticality prior to movement of irradiated fuel assemblies in the reactor vessel ensures that sufficient time has elapsed to allow the radioactive decay of the short-lived fission products. This decay time is consistent with the assumptions used in the safety analyses.

3/4.9.4 CONTAINMENT BUILDING PENETRATIONS

The requirements on containment building penetration closure and OPERABILITY ensure that a release of radioactive material within containment will be restricted from leakage to the environment. The OPERABILITY and closure restrictions are sufficient to restrict radioactive material release from a fuel element rupture based upon the lack of containment pressurization potential while in the REFUELING MODE.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity conditions during CORE ALTERATIONS.

3/4.9.6 REFUELING MACHINE

The OPERABILITY requirements of the refueling machine and auxiliary hoist ensure that:

(1) The refueling machine will be used for the movement of fuel assemblies and/or rod control cluster assemblies (RCCA) or thimble plug assemblies, and the auxiliary hoist will be used for the movement of control rod drive shafts,

(2) the refueling machine will have sufficient load capacity to lift a fuel assembly and/or a rod control cluster assembly or thimble plug assembly, and the auxiliary hoist will have sufficient load capacity to lift a control rod drive shaft and attached RCCA, and

(3) the core internals and reactor vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE AREAS

The restriction on movement of loads in excess of the nominal weight of a fuel and control rod assembly and associated handling tool over other fuel assemblies in the storage pool ensures that in the event this load is dropped: (1) the activity release will be limited to that contained in a single fuel assembly, and (2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

3/4.9.8 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

The requirement that at least one residual heat removal (RHR) train be in operation ensures that: (1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor vessel below 140°F as required during the REFUELING MODE, and (2) sufficient coolant circulation is maintained through the core to minimize the effect of a boron dilution incident and prevent boron stratification.

The requirement to have two RHR trains OPERABLE when there is less than 23 feet of water above the reactor vessel flange ensures that a single failure of the operating RHR train will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and at least 23 feet of water above the reactor pressure vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR train, adequate time is provided to initiate emergency procedures to cool the core.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 28 TO FACILITY OPERATING LICENSE NPF-68

AND AMENDMENT NO. 9 TO FACILITY OPERATING LICENSE NPF-81

GEORGIA POWER COMPANY, ET AL.

DOCKETS NOS. 50-424 AND 50-425

VOGTLE ELECTRIC GENERATING PLANT, UNITS 1 AND 2

1.0 INTRODUCTION

By letter dated November 21, 1989, Georgia Power Company (the licensee) requested changes to Technical Specifications (TSs) 3/4.4.1.4.2 and 3/4 9.1 for the Vogtle Electric Generating Plant, Units 1 and 2. These changes enable non-borated chemical additions to be made to the Reactor Coolant System (RCS) during Mode 5b (cold shutdown, loops not filled) and Mode 6 (refueling) using a flow path via the Reactor Makeup Water Storage Tank (RMWST). Use of this flow path requires that valves 1208-U4-176 and 1208-U4-177 be opened periodically under administrative control. The existing TSs require that these valves be closed and secured.

2.0 EVALUATION

Of the accidents and transients addressed in the Vogtle Final Safety Analysis Report (FSAR), the boron dilution event is the only transient that could be affected by the proposed TS revisions. The prolonged and unmonitored addition of an unborated chemical solution into the RCS for purposes of controlling RCS chemistry could lead to a complete loss of shutdown margin.

FSAR Section 15.4.6 presents boron dilution analyses for Modes 3, 4, and 5a (loops filled) in accordance with Standard Review Plan (SRP) Section 15.4.6. The analyses verify that adequate operator time (at least 15 minutes) is available to terminate the dilution flow between the time a "high flux at shutdown" alarm is received and when criticality occurs. However, boron dilution analyses for Modes 5b and 6 do not exist because TS 3/4.4.1.4.2 and 3/4.9.1 assure that possible dilution flow paths are isolated by closing and securing the appropriate valves, thereby administratively precluding a boron dilution event.

To permit chemical additions to be made to the RCS during Modes 5b and 6 using a flow path via the RMWST through the chemical mixing tank, valves 1208-U4-176 and 1208-U4-177 must be opened. In this regard, the licensee has proposed revisions to the above referenced TSs and has performed boron dilution analyses for these modes and this particular dilution path in accordance with SRP Section 15.4.6. The SRP acceptance criteria for Modes 5b and 6 are minimum operator action times of 15 minutes and 30 minutes, respectively.

9003080212

The licensee's analyses to determine minimum operator action times make use of conservative assumptions regarding boron dilution rate and active reactor coolant volume, as suggested in the SRP. A dilution flow rate of 3.5 gpm, representing the maximum rate possible via the proposed flow path under any operating condition, has been assumed. Additionally, the minimum cold drained reactor vessel volume has been utilized in the analyses, and the active RCS volume further minimized by assuming only one residual heat removal train in operation, considering miniflow and bypass lines to be empty, and neglecting reactor coolant loop volumes. Also, the source range "high flux at shutdown" alarm is assumed to be operable with a setpoint of 2.3 times background, as required by TS Table 4.3-1, Note 9. Shutdown margin requirements, as specified by TS 3.1.1.2 for Mode 5 and TS 3.9.1 for Mode 6, are also unchanged. The results of the licensee's analyses indicate that the minimum acceptable operator action times of 15 minutes for Mode 5b and 30 minutes for Mode 6, as specified in the SRP, are met.

We have reviewed the licensee's analyses as provided in the November 21, 1989, submittal and find that conservative assumptions have been used, the SRP acceptance criteria have been met or exceeded, and that the proposed TS changes will not have any adverse affect on safety. Any other boron dilution paths will continue to be precluded by the TSs.

On the basis of the above evaluation, the NRC staff concludes that the proposed TSs changes are acceptable.

3.0 ENVIRONMENTAL CONSIDERATION

The amendments involve changes in requirements with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and changes in surveillance requirements. The staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

4.0 CONCLUSION

The Commission made a proposed determination that the amendments involve no significant hazards consideration which was published in the Federal Register on December 27, 1989 (54 FR 53205), and consulted with the State of Georgia. No public comments were received, and the State of Georgia did not have any comments.

The staff has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (2) such activities will be conducted in compliance with the Commission's regulations, and the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: H. I. Abelson, SRXB/DST

Dated: February 20, 1990

GP-15309

Westinghouse Electric Corporation

Energy Systems

Nuclear Services Division

Box 355
Pittsburgh Pennsylvania 15230-0355

August 16, 1991

NSL-OPL-I-91-490

Ref: 1) Log: ELV-03040
2) GP-14649
3) WCAP-11338

Mr. C. K. McCoy
Vice President, Nuclear, Vogtle Project
Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

VOGTLE ELECTRIC GENERATING PLANT
UNIT 1
Mode 5b Boron Dilution

Dear Mr. McCoy:

Georgia Power Company has requested that Westinghouse examine the effect of opening Chemical and Volume Control System Valves (CVCS) 1208-U4-176 and 177 during Mode 5b (RCS drained to mid loop) operation at the end of Cycle 1 for Vogtle Unit 1. The Boron Dilution event in Mode 5b, with the above valves open, was not specifically analyzed for Cycle 1 because it was administratively precluded from occurring. Thus, Georgia Power Company requested that the event in this mode f Cycle 1 be specifically addressed, as outlined in Reference 1.

Analyses performed for Vogtle Unit 1 demonstrate that the Mode 5b boron dilution event, with the above mentioned valves open and the Cycle 1 high flux at shutdown setpoint of 3.16, will yield acceptable results for Cycle 1. The analyses used assumptions consistent with those presented in Reference 2, but with a high flux at shutdown setpoint of 3.16. The analyses were performed with initial boron concentrations specifically requested by Georgia Power Company. Two cases were examined. Case 1 assumed an initial boron concentration of 774 ppm and Case 2 assumed 1130 ppm (see Reference 1), based on the time that the CVCS valves were open. These two cases also assumed a critical boron concentration of 515 ppm (see Table 6.1 of Reference 3 for End of Life Conditions, $68^{O}F$), per Georgia Power's request.

The results of the Case 1 and 2 analyses are summarized in Table 1 on the following page. Specifically, the analysis demonstrates that there was more than 15 minutes (minimum acceptance criterion) from the time of alarm prior to criticality for the operator to take appropriate actions to mitigate the Boron Dilution event.

If there are any questions, please contact Steve DiTommaso at (412) 374-5277.

Sincerely,

WESTINGHOUSE ELECTRIC CORPORATION

E. Kurt Haub

J. L. Tain, Manager
Georgia Power Company Projects

Attachment

cc:	C. K. McCoy	1L, 1A
	R. J. Bush	1L, 1A
	NORMS (Vogtle Site)	1L, 1A
	G. L. Greenwood	1L, 1A
	P. D. Rushton	1L, 1A
	W. B. Shipman	1L, 1A
	L. A. Ward	1L, 1A
	A. E. Cardona	1L, 1A
	R. Florian	1L, 1A

637C:mmr/081691

Table 1

Boron Dilution Results for Mode 5 - Drained Down

Case	Initial Boron Conc.	Total Time	Time from Alarm to Crit.
1	774 ppm	2900 min	538 min
2	1130 ppm	5593 min	>1000 min

Acceptance Criterion = 15 minutes

Interpretation:

Voluntary Entry into Action Statement Conditions of the Technical Specifications (TS).

Purpose:

To provide the NRC position concerning Voluntary Entry into TS Action Statement Conditions.

Discussion:

10 CFR 50.36(c)(2) describes the limiting conditions for operation as the lowest functional capability or performance level of equipment that is required for the safe operation of the facility. Paragraph 50.36(c)(2) also states that the licensee shall shutdown the reactor or follow any remedial action permitted by the TS whenever a limiting condition for operation cannot be met.

The NRC endorses Voluntary Entry into the Action Statement Conditions and has structured the TS to permit the licensee to exercise judgment within the latitude permitted by the Action Statement language in the TS. The TS also restricts facility operation in the specified degraded mode of operation to the limited period of time designated in the related TS. In addition, Item 3.0.4 of the STS prohibits entry into an operational mode unless the conditions for the limiting condition for operation are met without reliance on provisions contained in the action requirements. This latter item provides assurance that all operability requirements are satisfied prior to the most recent startup.

Reference:

Memorandum, B. K. Grimes to S. E. Bryan; dated June 13, 1979.

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

June 13, 1979

MEMORANDUM FOR: Samuel E. Bryan, Assistant Director for Field Coordination

FROM: Brian K. Grimes, Assistant Director for Engineering and Projects

SUBJECT: CLARIFICATION OF STS: AC AND DC DISTRIBUTION

As requested in your memo dated March 8, 1979 (which forwarded J. Streeter's memo dated January 29, 1979), we have reviewed the STS relative to AC and DC electrical power distribution. In the development of these specific technical specifications, as well as throughout the entire STS package, it has been our intent that the licensee not be required to assume a snowball effect of the type suggested in J. Streeter's memo. It has been our intent that when an item is addressed in a LCO, the specific Action statement provided for that LCO be the governing requirement for continued plant operation.

The Action statements in the STS are provided in response to 10 CFR Part 50.36(c)(2) which states in part: "When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met". We believe that for a relatively short time period (within the time limits specified in the various STS Action statements) it is usually safer to permit plant operations to continue rather than to require initiation of a shutdown transient.

A second concern expressed in J. Streeter's memo was that the STS do not preclude having a diesel generator associated with one AC/DC bus train inoperable and concurrently an inoperable battery in the other DC train. This scenario was recognized and considered during the development of the STS. We do not believe that any further actions are required nor are any further actions planned at this time since operation in the postulated conditions would be very limited. The Action statement for Specification 3.8.2.3 permits plant operation to continue for a maximum of 2 hours after which the inoperable battery must either be returned to operable status or a plant shutdown must be initiated and the unit must be in hot standby within the following 6 hours. The allowable out of service times specified in the STS for the AC and DC electrical power supplies are consistent with the recommendations of Regulatory Guide 1.93.

The third concern expressed in J. Streeter's memo was that licensees may voluntarily enter technical specification action statements associated with AC and DC distribution by closing tie breakers between redundant buses. In response to this concern, it should be noted that throughout the STS, and typically in the custom technical specifications, the licensee is

790807 0039

XA

not prohibited from voluntarily entering action statements. We believe it is necessary and desirable to structure the technical specification to permit the operator to exercise judgment within the latitude permitted by Technical Specifications. It should be further noted that during operation in a degraded mode under the provisions of an action statement, the facility may not be capable of responding to an initiating event plus a concurrent or subsequent single failure of an active component. Therefore, the action statements restrict operation in the specified degraded mode of operation to a limited period of time. We are not aware of instances in which licensees have abused the provisions of being able to voluntarily enter Action statements; however, if a licensee should frequently initiate such activities, please bring it to our attention and we will consider further actions on a case basis. Additionally, we would call your attention to Specification 3.0.4 in the STS which prohibits entering an operational mode unless the operability requirements of the limiting condition for operation are satisfied without reliance on the provisions of the associated Action statement. This prevents startup when the opportunity is available to meet the operability requirements without initiating a shutdown transient.

A fourth concern expressed was that the acceptance criteria of 1.200 for the battery specific gravity was overly restrictive. This item is a plant specific value in the STS and the value of 1.200 was supplied by the applicant/licensee as being the applicable value, in accordance with the recommendations of Regulatory Guide 1.129, for the subject battery. This value was reviewed by NRR during the preparation of the subject technical specifications and no further actions are considered necessary at this time.

We hope that these comments have resolved the problems you raised. D. Brinkman is available for further clarification as necessary.

Brian Grimes

Brian K. Grimes, Assistant Director
for Engineering and Projects
Division of Operating Reactors

cc: V. Stello
D. Eisenhut
DOR Project Branch Chiefs
STS Group Members
D. Tondi

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

December 27, 1990

Mr. Kenneth A. Strahm
Executive Vice President
Institute of Nuclear Power Operations
1100 Circle 75 Parkway
Atlanta, GA 30339

Dear Mr. Strahm:

The NRC staff has noticed an increased tendency to perform preventive maintenance during power operation. This includes maintenance of equipment required to be operable by technical specifications. In order to perform this maintenance, utilities enter action statements of the Limiting Conditions for Operation (LCOs) in their technical specifications. While it appears that utilities are attempting to limit the amount of time spent in an LCO to a reasonable fraction of the total outage time allowed by the LCO, in some cases the preventive maintenance may be repeated several times during an operating cycle. This leads to a concern that the total unavailability of important plant equipment may be higher than originally contemplated. Of special concern is the entering into an LCO near the end of an operating cycle for the primary purpose of performing preventive maintenance in order to shorten the refueling outage. A frequently encountered example is the overhaul of diesel generators.

Several factors may have contributed to this increase in on-line preventive maintenance; among these appears to be the influence of INPO in encouraging utilities to limit the length of outages. For example, INPO 8C-017, pg. 8, encourages utilities, "...to maximize the amount of work done on-line."

The NRC staff is concerned that the impetus to perform more preventive maintenance on-line may not have been thoroughly considered from the safety (risk) perspective. In some instances the increase in on-line preventive maintenance which requires entering LCO action statements may contribute to more reliable on-line performance of important plant equipment and enhance overall safety. However, on-line maintenance primarily for the purpose of limiting plant outage time or other operational convenience, should not be undertaken without a full appreciation of the effects of this practice on plant safety.

It should be kept in mind that the allowed outage time set by an LCO takes into account the single failure criterion, which is an important assumption in the overall facility safety analyses. We therefore consider the frequent entering of an LCO action statement to perform preventive maintenance, or performing extensive preventive maintenance on important safety equipment for the purpose of reducing outage time, to be outside of the original intent of the technical specifications allowed outage time.

Although we believe a well founded preventive maintenance program can contribute to plant safety and reliability, we also believe that licensees should develop

9104110128

RECEIVED DEC 28 1990

a full understanding of the impact on plant safety when removing equipment from service for preventive maintenance. This may be an area where INPO could take a significant leadership role.

I would be pleased to discuss this matter further at your convenience.

Sincerely,

James H. Sniezek

James H. Sniezek
Deputy Executive Director
for Nuclear Reactor Regulation
Regional Operations and Research

cc: Z. Pate, INPO
J. Colvin, NUMARC

MAINTENANCE - VOLUNTARY ENTRY INTO LIMITING CONDITIONS FOR OPERATION ACTION STATEMENTS TO PERFORM PREVENTIVE MAINTENANCE

A. PURPOSE

To provide a set of safety principles for guiding the performance of preventive maintenance (PM) at licensed nuclear reactor facilities when the performance of the PM requires rendering the affected system or equipment inoperable (on-Line PM). Although these principles apply primarily to PM during power operation, they also apply to PM on equipment that must be OPERABLE during shutdown evolutions such as fuel handling or mid-loop operation.

This guidance provides qualitative criteria to assist in recognizing abuses of on-line PM. If such abuses are noted, they should be discussed with NRC management before they are discussed with the licensee. This should ensure that the guidance is applied in a reasonable and consistent manner for all licensees.

B. BACKGROUND

The NRC has not previously established guidance on taking equipment out of service to perform PM because the NRC did not expect licensees to routinely perform such PM when technical specifications require the equipment to be OPERABLE. Rather, it was expected that most PM that necessitated taking equipment out of service would be accomplished at a time when the safety function performed by the equipment was not needed, (e.g., when the facility is shutdown). Performing such PM (e.g., emergency diesel generator overhaul at power) requires intentionally entering the technical specifications (TS) limiting conditions for operation (LCO) for the affected system. If a licensee does this, it must complete the PM and restore compliance with the LCO OPERABILITY requirements within the time specified in the appropriate action statement of the LCO (i.e., the allowed outage time (AOT)). Intentional entry into an action statement of an LCO is not a violation of the TS (except in certain cases, such as intentionally creating a loss of function situation or entering LCO 3.0.3). For example, TS allow licensees to perform much surveillance testing during power operation, even though such testing requires entry into LCO action statements. TS permit entry into LCO action statements to perform surveillance testing for a number of reasons. One reason is that the time needed to perform most surveillances is usually only a small fraction of the AOT specified in the action statement.

Another reason is that the benefit to safety (increased level of assurance of reliability and verification of OPERABILITY) derived from meeting surveillance requirements is considered to more than compensate for the risk to safety from operating the facility in an LCO action statement for a small fraction of the AOT.

The NRC staff has noticed a trend at many licensed nuclear facilities to perform increasing amounts of PM during power operation (on-line PM) rather than during shutdown conditions. By performing more on-line PM, licensees must intentionally enter into LCOs more frequently than before and use more of the AOTs than would normally be used by surveillance testing alone. This could cause the total unavailability of equipment over each operating cycle (or the total time that a facility operates at increased risk because it is not complying with LCO OPERABILITY requirements and is vulnerable to single failures) to become greater than originally contemplated when TS were established. Of special concern is intentional entry into LCOs to perform PM near the end of an operating cycle primarily in order to shorten the refueling outage.

The NRC is only beginning to quantitatively study the significance to safety (risk) of the trend to perform more PM during power operation. Therefore, the NRC can not yet establish quantitative criteria by which the NRC or a licensee can determine the net effect on safety that on-line PM would have at a facility. Until studies concerning the risk of on-line PM are completed, this guidance establishes conservative principles for safely performing PM that involves entering into LCO action statements.

C. DISCUSSION

A licensee may take equipment out of service to perform PM during power operation of the facility (on-line PM) if it expects the reliability of the equipment to improve such that the overall risk to safe operation of the facility should decrease. Licensees' expectations should take into account that such practice may increase the unavailability of the equipment. When performing PM on equipment not in TS (i.e., equipment that has no TS AOT), licensees should be sensitive to the principles embodied by the TS definition of OPERABILITY and the effect upon the OPERABILITY of TS equipment.

If a licensee has a reasonable expectation that an on-line PM program will improve safety by making equipment more reliable, then the licensee can implement that program even though it may increase the unavailability of equipment. The licensee should be able to justify such an expectation of improved safety. Part of this justification should be based upon adherence to the following conservative safety principles:

1. Performance of a PM action on-line rather than during shutdown should improve safety (as described above) and be warranted by operational necessity, not just by the convenience of shortening a refueling outage.

2. The licensee should not abuse the allowance to perform a PM action on-line by repeatedly entering and exiting LCO action statements. The licensee should carefully plan the PM action to prevent such abuse.

3. While performing an on-line PM action, the licensee should avoid removing other equipment from service. Confidence in the OPERABILITY of the independent equipment that is redundant (or diverse) to the affected equipment should be high. If a piece of equipment is OPERABLE, but is degraded, or is trending towards a degraded condition, the licensee should not remove its redundant counterpart equipment from service for a routine PM action.

4. While performing an on-line PM action, the licensee should avoid performing other testing or maintenance that would increase the likelihood of a transient. The licensee should have reason to expect that the facility will continue to operate in a stable manner. (The basis of this expectation should include a consideration of degraded or out of service balance of plant equipment.)

END

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
TECHNICAL SPECIFICATIONS BRANCH

NUREG/BR-[illegible]
ISSUE NO. 87-2
AUGUST 1987

TECHNICAL SPECIFICATION IMPROVEMENT PROGRAM HIGHLIGHTS

This is the second issue of the TECHNICAL SPECIFICATIONS IMPROVEMENT PROGRAM HIGHLIGHTS. These highlights are being issued regularly by the Technical Specifications Branch in an effort to keep both Headquarters and Regional staff informed of important developments in the joint NRC/industry program to implement the recently issued Commission Policy Statement on Technical Specifications Improvement. Comments or suggestions for future issues should be referred directly to Millard Wohl, Mail Stop 516, telephone extension x27458.

- <u>STAFF APPROVES BWR OWNERS GROUP TOPICAL REPORT NEDC-30851 P, "TECHNICAL SPECIFICATION IMPROVEMENT ANALYSES FOR BWR REACTOR PROTECTION SYSTEM"</u>

  The staff issued an SER on the above topical report to the BWR Owners Group chairman on July 15, 1987. The staff acceptance of this topical report will permit certain BWR licensees to extend the current weekly and monthly RPS sensor channel functional test intervals to quarterly intervals for BWR relay-type RPS plants. Allowable repair and test times of 1 hour and 2 hours for the BWR RPS relay sensor channels are extended to 12 hours and 6 hours, respectively.

  CONTACTS: T. Collins, x29463
  K. Desai, x27952

- <u>STAFF REVISES TECHNICAL SPECIFICATION IMPROVEMENT PROGRAM PLAN</u>

  A revised NRC Technical Specification Improvement Program Plan has been developed in response to the Commission's recently promulgated Interim Policy Statement on Technical Specification Improvement. The Program Plan as revised now emphasizes the details of how to implement (as opposed to develop) the Commission's Policy Statement.

  One section of the Program Plan lists those tasks, along with a schedule for completion, necessary to develop the completely rewritten Standard Technical Specifications (STS) called for in the Policy Statement. The objective of rewriting the STS is to reduce their size and complexity by retaining only requirements of prime safety importance and to incorporate human factors and other general improvements in order to make Technical Specifications more understandable. As a result, the new STS will be a more effective tool for assuring plant safety. Once developed, the new STS will be implemented at individual plants through plant-specific license amendments.

  Another section of the Program Plan is devoted to activities aimed at improving the technical substance of specific line item requirements in the Technical Specifications. These activities include such things as a reevaluation of the appropriateness of current action statements, allowed outage times, and surveillance intervals.

The Program Plan, now in its early stages of implementation, carries with it a central theme of the Commission's Policy Statement, that of a voluntary, cooperative, joint NRC and industry approach to Technical Specifications improvement. Many of the activities in the Plan require detailed submittals from industry working groups. These activities were discussed with the appropriate industry representatives while they were being defined and the NRC expects the full support of the industry in this important program.

CONTACT: D. Fischer, x27465

VOLUNTARY ENTRY INTO TECHNICAL SPECIFICATION ACTION STATEMENTS

Action Statements establish time limits for implementing remedial measures when a Limiting Condition for Operation (LCO) is not met. This time limit is commonly referred to as the Allowable Outage Time (AOT) since it defines a limiting time duration for which a system or component may be out of service for corrective maintenance when it is found to be inoperable. The AOTs also establish the limiting time durations for which a system or component may be voluntarily removed from service for surveillance testing or investigation of operational problems. Generally the TS require an orderly plant shutdown when the stated remedial action is not completed within the limits of the AOT.

Specification 3.0.3 in the Standard Technical Specifications establishes the time limits for an orderly plant shutdown which apply when the action requirements do not specify a remedial measure for a condition where the LCO is not met. Recently it has come to NRR's attention that some licensees have voluntarily entered the forced plant shutdown requirements of Specification 3.0.3 as an operational convenience. An example is the removal of redundant systems from service to perform a surveillance test. Since such actions remove the last echelon of defense against deleterious events, NRR has alerted Regional Administrators* that voluntary use of Specification 3.0.3 is unacceptable as an operational convenience in lieu of other courses of action. The updated Bases for the general requirements that are applicable to LCOs and surveillance requirements included in Generic Letter 87-09 reflect these positions.

*Memorandum from Thomas E. Murley, Director, NRR to Regional Administrators, dated June 17, 1987.

CONTACT: T. G. Dunning, x28434

NRC CONTRACTOR COMPLETES "A REVIEW OF THE COMBUSTION ENGINEERING EVALUATION FOR EXTENDING THE RPS AND ESFAS TEST INTERVALS"

On 7/20/87, the staff received a draft Technical Evaluation Report (TER) on the CE Owners Group topical report CEN-327, "RPS/ESFAS Extended Test Interval Evaluation." The EG&G

23 Southampton Court
Newport Beach, CA 92660

July 2, 1991

Mr. George Hairston
Senior Vice President
Georgia Power Company
P. O. Box 1295
Birmingham, AL 35201

Dear George,

It was nice talking to you again after all these years. As hectic as it was, I remember my period with Westinghouse on the Standard Tech Specs as one of the most exciting periods in my early career. I'm sorry to hear of your problems with them after all these years but feel good about the fact that work we did in the early 1970's is still important to the nuclear industry -- it somehow makes all the long days over the years somehow worthwhile. As you now realize I left this arena later in the 1970's although I remained at Westinghouse in other capacities until late in 1989 when I joined my current employer.

As we discussed this week, I remember many of our discussions with the NRC concerning the use of the term "IMMEDIATE" in any enforceable "REQUIRED ACTION". As we jointly discussed with the NRC in the 1970's, in nuclear power plants the safest solution is not always a precipitous action taken based on incomplete data. We debated long and hard over this issue with the NRC and, as I remember it, they ultimately agreed that we would have to better define our intent in using the term "IMMEDIATE". At first I believe they proposed to define the term in the "DEFINITION" section of the tech spec and that we talked in terms of 10-20 minutes as an appropriate immediate response for most occurrences requiring prompt decision making and action. Ultimately, I thought the NRC decided to discontinue use of the word "IMMEDIATE" and place actual time limits in each action item so that operators would not be faced with debating in their minds, while under pressure, the intent of the NRC. As far as I can remember, the term "IMMEDIATE" was removed from all specifications.

If I can be of further assistance, please feel free to call me again.

very truly yours,

C. C. Little

Charles C. Little

STATEMENT

July 12, 1991

I, the undersigned, was on the staff of the United States Nuclear Regulatory Commission (USNRC), formerly the Atomic Energy Commission (AEC), from August 1968 through October 1978. During the period of time from 1973 through 1978, I conceived, developed and implemented the Standard Technical Specification Program for the Commission.

There were a number of objectives to be achieved in developing the STS's. Obviously, the primary objective was to have consistent specifications among the various plants being placed into service by each of the reactor vendors. There were however, secondary objectives to be achieved. One of these was to have specifications which were clear and unambiguous and easily understood by an operator faced with a situation requiring action at 3:00 AM in the morning. This issue of clarity is the subject of this statement.

One of the first draft issues of the STS's had a number of action statements which required operator action on an "immediate" basis. As the STS's evolved, it became apparent that trying to define "immediately" was an impossible task given the varying degree of severity the "Action" statement was being required to cover.

Eventually, the term "immediately" was replaced by a series of time dependent "Action" statements which were tailored to the severity of the situation and took into account the ability of the physical plant to respond to the required change in a given time period. This change represented a substantial improvement in the STS's and was endorsed by the ANS 58.4 Standards Committee on Standard Technical Specifications.

JM McGough

J.M. McGough

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

May 20, 1977

MEMORANDUM FOR: G. Fiorelli, Chief, Reactor Operations and Nuclear Support Branch, RIII

FROM: J. H. Sniezek, Assistant Director for Field Coordination, ROI/IE

SUBJECT: OPERABILITY DEMONSTRATION OF REDUNDANT SYSTEMS (F30290H1)

We have discussed with DOR the issue raised in your memorandum of April 27, 1977. The NRC philosophy of testing redundant systems when one system fails is undergoing a change. The current feeling is that to take its redundant system out of service for testing, if the first system fails, creates the risk of the second system also failing. It has been observed that failures of the second system are often related to the test itself and is not an indication that the system would have failed should it have been needed.

All current STS reflect this thinking and some TS changes are occurring to improve older TS. Some older facilities, however, are reluctant to accept this improvement because in order to justify not immediately testing the redundant system, that system must be routinely tested at an increased interval. DOR will not accept a deletion of immediate redundant testing without improved routine surveillance frequencies.

To specifically answer your request that "immediate" be interpreted as within four hours, it was felt that this could not be generally applied. In some cases it might be too long while in other cases the four-hour period might create a rushed situation that would result in an increased probability of human failure resulting in a loss of the backup system. How soon the test should be conducted will depend on the cause of the system failure. As a guideline, if the failure was generic such that the redundant system might not function for the same reason, then the test should be completed as soon as possible. On the other hand, if it is not likely that the second system will fail by the same mode, then there is less urgency to conduct the test. Thus, for the present, the NRC will rely on the technical judgment of the NRC inspection staff on a case-by-case basis.

~~8402090420~~

J H Sniezek
J. H. Sniezek
A/D for Field Coordination

cc w/incoming:
~~J. M. McGough~~, NRR
E. J. Brunner, RI
F. J. Long, RII
G. L. Madsen, RIV
J. L. Crews, RV
K. V. Seyfrit, IE

CONTACT: G. L. Constable
49-27451

C. Core Alteration - Core alteration shall be the addition, removal, relocation, or movement of fuel, sources, incore instruments, or reactivity controls within the reactor pressure vessel with the vessel head removed and fuel in the vessel. Suspension of core alterations shall not preclude completion of the movement of a component to a safe conservative position.

D. Design Power - Design power refers to the power level at which the reactor is producing 105 percent of reactor vessel rated steam flow. Design power does not necessarily correspond to 105 percent of rated reactor power. The stated design power in megawatts thermal (MWt) is the result of a heat balance for a particular plant design. For Hatch Nuclear Plant Unit 1 the design power is approximately 2537 MWt.

E. Engineered Safety Features - Engineered safety features are those features provided for mitigating the consequences of postulated accidents, including for example containment, emergency core cooling, and standby gas treatment system.

F. Hot Shutdown Condition - Hot shutdown condition means reactor operation with the Mode Switch in the SHUTDOWN position, coolant temperature greater than 212°F, and no core alterations are permitted.*

G. Hot Standby Condition - Hot standby condition means reactor operation with the Mode Switch in the START & HOT STANDBY position, coolant temperature greater than 212°F, reactor pressure less than 1045 psig, critical.

H. Immediate - Immediate means that the required action shall be initiated as soon as practicable, considering the safe operation of the Unit and the importance of the required action.

I. Instrument Calibration - An instrument calibration means the adjustment of an instrument output signal so that it corresponds, within acceptable range and accuracy, to a known value(s) of the parameter which the instrument monitors.

J. Instrument Channel - An instrument channel means an arrangement of a sensor and auxiliary equipment required to generate and transmit to a trip system a single trip signal related to the plant parameter monitored by that instrument channel.

---

*During the performance of inservice hydrostatic or leakage testing with all control rods fully inserted and reactor coolant temperature > 212°F, and/or reactor vessel pressurized, the reactor may be considered to be in the Cold Shutdown Condition for the purpose of determining Limiting Condition for Operation applicability. However, compliance with an ACTION requiring COLD SHUTDOWN shall require a reactor coolant temperature ≤ 212°F.

S10 910410 867

Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

Joseph R. Bynum
Vice President, Nuclear Operations

April 10, 1991

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Gentlemen:

TENNESSEE VALLEY AUTHORITY - SEQUOYAH NUCLEAR PLANT UNIT 2 - DOCKET NO. 50-328 - FACILITY OPERATING LICENSE DPR-79 - LICENSEE EVENT REPORT (LER) 50-328/91003

The enclosed LER provides details concerning the discovery of the breaker for the Unit 2 No. 3 cold leg accumulator isolation valve being in the locked closed (power on) position. Technical Specification (TS) Surveillance Requirement 4.5.1.1.1.c requires that the valve be open with power removed. This event is being reported in accordance with 10 CFR 50.73(a)(2)(i)(B) as an operation prohibited by TSs and 10 CFR 50.73(a)(2)(ii)(B) as a condition that was outside the design basis of the plant.

Mr. Bill Little, of your NRC staff, was notified on April 2 and again on April 5, 1991, that issuance of this LER was delayed, and that the LER would be issued by April 12, 1991.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

J. R. Bynum

Enclosure
cc: See page 2

9104170202

77SRB

U.S. Nuclear Regulatory Commission

April 10, 1991

JLW:MAC:JWP:GC
Enclosure
cc (Enclosure):

Mr. D. E. LaBarge, Project Manager
U.S. Nuclear Regulatory Commission
One White Flint, North
11555 Rockville Pike
Rockville, Maryland 20852

INPO Records Center
Institute of Nuclear Power Operations
1100 Circle 75 Parkway, Suite 1500
Atlanta, Georgia 30339

NRC Resident Inspector
Sequoyah Nuclear Plant
2600 Igou Ferry Road
Soddy Daisy, Tennessee 37379

Mr. B. A. Wilson, Project Chief
U.S. Nuclear Regulatory Commission
Region II
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

RIMS, MR 2F-C
W. R. Cobean, Jr., LP 6A-C
D. L. Conner, STC 2H-SQN
M. A. Cooper, OPS 4C-SQN
(Attn: J. S. Smith)
J. B. Garrity, FSB 1A-WBN
R. L. Lumpkin, Jr., SB 1C-SQN
R. W. Martin, OPS 4B-SQN
(Attn: T. J. Hollomon)
F. C. Mashburn, SBT 1A-SQN
T. J. McGrath, LP 6A-C
M. O. Medford, LP 6A-C
Nuclear Experience Review Files, OPS 4D-SQN
P. Salas, PAB J-BFN
R. H. Shell, LP 5B-C
P. G. Trudel, DSE 1A-SQN
E. G. Wallace, LP 5B-C
J. L. Wilson, OPS 4A-SQN

4/15/91
4-10-91

SQ-OHM-REV

1352h

LICENSING TRANSMITTAL TO NRC
SUMMARY AND CONCURRENCE SHEET

THE PURPOSE OF THIS CONCURRENCE SHEET IS TO ASSURE THE ACCURACY AND COMPLETENESS OF TVA SUBMITTALS TO THE NRC.

DATE ______ ________ ORIGINAL DATE DUE NRC 4/1/91 - C EXTENDED DATE DUE NRC ________

SUBMITTAL PREPARED BY Gregory S. Kniedler ACTION NO. ________

FEES REQUIRED YES ___ NO XX

PROJECT/DOCUMENT I.D. Sequoyah Nuclear Plant (SQN) - Licensee Event Report (LER) 50-328/91003

PURPOSE/SUMMARY To provide NRC with LER 50-328/91003 concerning the discovery of the breaker for the Unit 2 No. 3 cold leg accumulator (CLA) isolation valve being in the lock closed position. Technical Specification Surveillance Requirement 4.5.1.1.1.c requires that the valve be operable with power removed.

RESPONDS TO N/A (RIMS NO.) COMPLETE RESPONSE YES XX NO ___

PROBLEM OR DEFICIENCY DESCRIPTION Failure to remove power from the breaker of the isolation valve operator for the No. 3 CLA, therefore operating in a condition prohibited by TS and outside of the design basis.

CORRECTIVE ACTION/COMMITMENT See corrective action section.

INDEPENDENT REVIEW ________________ DATE ________

A concurrence signature reflects that the signatory has assured that the submittal is appropriate and consistent with TVA Policy, applicable commitments are approved for implementation, and supporting documentation for submittal completeness and accuracy has been prepared.

CONCURRENCE

NAME	ORGANIZATION	SIGNATURE	DATE
J. L. Wilson	SQN Site Vice President	J L Wilson	4.10.91
R. J. Beecken	SQN Plant Manager	R J Beecken	4/10/91
PORC Chairman		R J Beecken	4/10/91
P. G. Trudel	SQN Project Engineer	P G Trudel	4/10/91
M. A. Cooper	SQN Site Lic Mgr	M A Cooper	4/10/91

APPROVED M.A. Cooper DATE 4/10/91
NLRA MANAGER

1352h

Sequoyah Site Licensing

Concurrence Sheet

DATE ______________ ORIGINAL DATE DUE NRC 4/1/91 C EXTENDED DATE DUE NRC ______________

PROJECT/DOCUMENT I.D. Sequoyah Nuclear Plant (SQN) - Licensee Event Report (LER) 50-328/91003

Incident Investigation No. II-3-91-017

Cross Reference Documents (PER, CAQR, etc.) ______________

Verification by ______________

CONCURRENCE

NAME	ORGANIZATION	SIGNATURE OR LETTER REFERENCE	DATE
G. S. Kniedler	SQN Licensing Engineer	[illegible]	4/10/91
J. W. Proffitt	SQN Compliance Lic Mgr	[illegible]	4/10/91
J. S. Smith for	SQN Site Licensing	[illegible]	4/10/91
R. W. Martin	SQN Site Controller		
M. J. Lorek for	SQN Operations Superintendent	[illegible]	4-10-91
W. R. Lagergren	SQN Operations Manager	[illegible]	4-10-91
J. K. Gates	SQN Technical Support Manager	[illegible]	4-10-91

NRC response or approval required? ____ Yes X No

NOTE: This sheet should be removed by Corporate Licensing upon receipt.

1352h

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Sequoyah Nuclear Plant, Unit 2

DOCKET NUMBER (2): 0|5|0|0|0|3|2|8

PAGE (3): 1 OF 1

TITLE (4) Power not removed from cold leg accumulator isolation valve as a result of inappropriate personnel actions.

EVENT DAY (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 3	0 1	9 1	9 1	0 0 3	0 0	0 4	1 0	9 1		

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following)(11)

__ 20.402(b)	__ 20.405(c)	__ 50.73(a)(2)(iv)	__ 73.71(b)
__ 20.405(a)(1)(i)	__ 50.36(c)(1)	__ 50.73(a)(2)(v)	__ 73.71(c)
__ 20.405(a)(1)(ii)	__ 50.36(c)(2)	__ 50.73(a)(2)(vii)	__ OTHER (Specify in Abstract below and in Text, NRC Form 366A)
__ 20.405(a)(1)(iii)	XX 50.73(a)(2)(i)	__ 50.73(a)(2)(viii)(A)	
__ 20.405(a)(1)(iv)	XX 50.73(a)(2)(ii)	__ 50.73(a)(2)(viii)(B)	
__ 20.405(a)(1)(v)	__ 50.73(a)(2)(iii)	__ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
Gregory S. Kriedler, Compliance Licensing Engineer	6 1 5	8 4 3 - 7 4 6 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

__ YES (If yes, complete EXPECTED SUBMISSION DATE) | X | NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On March 1, 1991, at 0127 Eastern standard time (EST) with Unit 2 in Mode 1, it was discovered that the breaker for the operator for the No. 3 cold leg accumulator (CLA) isolation valve 2-FCV-63-80 was locked in the closed position. This was discovered during the performance of Surveillance Instruction (SI) 0-SI-OPS-063-013.0, "Cold Leg Accumulator Valves Power Removal Verification." The last documented manipulation of this breaker was on February 14, 1991, when an evolution was being performed in attempt to stop inleakage of reactor coolant into the CLA. This evolution was initiated at 2019 EST on February 14, 1991, and completed at 2032 EST with the components thought returned to their required conditions/positions. No independent verification of the breaker's restoration was performed. The cause of the event is attributed to inappropriate personnel actions. Immediate corrective action was to restore the breaker to its correct position. Additional corrective actions include discussions with Operations personnel to clarify requirements, disciplinary action, procedure clarifications, and further training.

9104170202

TEXT (If more space is required, use additional NRC Form 366A's) (17)

DESCRIPTION OF EVENT

On March 1, 1991, at 0127 Eastern standard time (EST), with Unit 2 operating in Mode 1, (100 percent power, 2,235 pounds per square inch gauge [psig], and 578 degrees Fahrenheit [F]), it was discovered that the breaker for the operator of the Unit 2, No. 3 cold leg accumulator (CLA) (EIIS code BQ) isolation valve, 2-FCV-63-80, was locked in the closed position. This was discovered during the performance of Surveillance Instruction (SI) 0-SI-OPS-063-013.0 "Cold Leg Accumulator Valves Power Removal Verification," which is required by Technical Specification (TS) Surveillance Requirement (SR) 4.5.1.1.1.c. SR 4.5.1.1.1.c requires that: "At least once every 31 days when the RCS pressure is above 2000 psig by verifying that power to the isolation valve operator is disconnected by removal of the breaker from the circuit." The TS basis for the requirements of TS 3.5.1.1 is "The accumulator power operated isolation valves are considered to be 'operating bypasses' in the context of IEEE Std. 279-1971, which requires that bypasses of a protective function be removed automatically whenever permissible conditions are not met. In addition, as these accumulator isolation valves fail to meet single failure criteria, removal of power to the valves is required." The shift operations supervisor (SOS) was immediately notified of this condition and TS Limiting Condition for Operation (LCO) 3.5.1.1 was entered at 0127 EST. The breaker was unlocked, opened, and locked in the open position (i.e., power removed) at 0131 EST and LCO 3.5.1.1 was exited.

On February 1, 1991, 0-SI-OPS-063-013.0 was performed and the breaker for the operator to 2-FCV-63-80 was verified in the locked open position as required by TS SR 4.5.1.1.1.c. On February 14, 1991, an evolution was initiated in an attempt to reduce the 0.21 gallons per minute (gpm) inleakage of the reactor coolant system (RCS) into the Unit 2, No. 3 CLA. The performance of this evolution was done in accordance with Administrative Instruction (AI) 30, "Nuclear Plant Conduct of Operation," which states: "Limited evolutions of short duration may be performed by an operator without a procedure provided that positive configuration control is maintained in accordance with AI-58, a procedure does not exist for the activity and the operation is not complex. The SOS and unit assistant shift operations supervisor (ASOS) will determine if any operation will be allowed without a procedure based upon the complexity, duration of the operation, TS requirements and Final Safety Analysis Report Description/Bases/Assumptions. Any evolution performed without a procedure shall be documented in the operator journal."

The evolution to stop the inleakage of RCS into the No. 3 CLA was to consist of unlocking and closing the breaker for valve 2-FCV-63-80, the repositioning of four valves (2-FCV-63-80, -78, -71, and -84), and the operation of the 2A Safety Injection System (SIS) pump. The Unit 2 ASOS was to remain at the breaker throughout the evolution to maintain positive control and the Unit 2 lead main control room (MCR) unit operator (UO) would maintain positive control over the valve manipulations in the MCR.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Sequoyah Nuclear Plant Unit 2	0 5 0 0 0 3 2 8	9 1	— 0 0 3 —	0 0	0 3 OF 1 1

TEXT (If more space is required, use additional NRC Form 366A's) (17)

DESCRIPTION OF EVENT

This lineup was intended to vent pressure from the upstream side of check valve 63-624 to the holdup tank and then apply a large differential pressure to backseat the check valve by starting the SIS pump. Refer to Updated Final Safety Analysis Report (UFSAR) Figure 6.3.2-1.

Before performing this evolution, the activity was discussed with the Operations Superintendent, the off-going SOS, the onshift SOS and the onshift Unit 2 ASOS. The activity was determined to constitute a limited evolution based on the small number of manipulations, anticipated short duration, and positive controls that would be implemented. The initial review for the evolution by the onshift SOS and onshift Unit 2 ASOS consisted of a review of flow prints, technical specifications, and procedures. Electrical prints were not reviewed. The evolution was initiated at 2019 EST on February 14, 1991, with entry into LCO 3.5.1.1. These activities were logged into the operator's log as required by AI-30 for limited evolutions. The Unit 2 ASOS unlocked and closed the breaker for the 2-FCV-63-80 operator. The Unit 2 lead UO then shut 2-FCV-63-80 from the MCR. The isolation valve automatically opened. This was reported to the ASOS at the breaker. The ASOS opened and then closed the control power breaker to the 2-FCV-63-80 operator to clear any possible lock-in safety injection signals. The ASOS then requested the UO to close 2-FCV-63-80 and it again reopened automatically. The ASOS locked the breaker open, then proceeded to the MCR to review drawings to determine what was preventing the valve from remaining closed. The P-11 interlock on 2-FCV-63-80 was identified by review of electrical prints. This interlock causes the valve to open automatically when the RCS pressure is greater than or equal to 1,970 pounds per square inch gauge (psig). Discussion with the SOS and Unit 1 ASOS took place to determine a course of action to address the P-11 interlock relative to 2-FCV-63-80. The Unit 2 ASOS returned to the location of the breaker for valve 2-FCV-63-80 and unlocked and closed the breaker. Valve 2-FCV-63-80 was then closed by the UO, the ASOS opened the breaker as soon as the valve indicated closed, and the valve remained closed. The Operations Superintendent was not recontacted or consulted when the interlock was encountered.

The evolution continued with the opening of valves 2-FCV-63-78, -71, and -84. Once the pressure in the line was relieved, valves 2-FCV-63-78 and -71 were closed, and the SIS pump 2A was started. After this evolution, valve 2-FCV-63-80 was opened, the SIS pump 2A was stopped, and valve 2-FCV-63-84 was closed.

The Unit 2 ASOS who performed the manipulations of the valve's motor-operator supply breaker, remained in the vicinity of the breaker when it was not in the locked open position. The evolution was completed with valves returned to their normal positions at 2032 EST, and LCO 3.5.1.1 was exited. Following the evolution the ASOS returned to the MCR. The SOS asked the ASOS if power had been removed from the operator to valve 2-FCV-63-80. The ASOS reported that power had been removed. This was logged in the SOS and ASOS logs. However, no independent verification was performed following system restoration as required by AI-37, "Independent Verification." AI-37, Section 6.1.2,

DESCRIPTION OF EVENT

requires that breakers in the Emergency Core Cooling System (ECCS) shall be independently verified to be in the correct position and/or condition when the system or component is being returned to service or restored to a stand-by line up. The stated objective of AI-37 is to minimize the possibility of human error in the performance of designated activities by verifying that the activity conforms to specified requirements.

The normal method of documenting independent verification is to use clearance sheets, system operating instruction power availability and valve checklists or AI-58, "Maintaining Cognizance of Operation Status - Configuration Status Control," Appendix B, "Configuration File Sheets." An allowable exception to configuration control requirements, according to AI-58, was followed. AI-58, Section 2.2.2.1, allows exceptions to requirements for configuration log entries if "equipment involved is continuously monitored by operator at local site until it is returned to NORMAL status." These requirements were met and accordingly no configuration log entries were made. As a result of the allowed exception of AI-58, Operations personnel assumed that independent verification was not absolutely required, i.e., since the evolution was not documented by the above noted normal methods; therefore, an independent verification was not performed.

Following discovery of power on the valve on March 1, 1991, an invustigation was conducted to evaluate potential causes of the mispositioning of the 2-FCV-63-80 motor operator breaker. Operator logs were reviewed to determine if any manipulations of the breaker occurred between February 14 and March 1, 1991. No evidence was identified of any operations of the breaker or valve other than that on February 14, 1991.

In response to a concern that a manipulation of the breaker for the operator to 2-FCV-63-80 could have occurred but not been logged, an extensive interview process was performed. SOSs, ASOSs, lead UOs, and balance of plant UOs who were assigned to operate Unit 2 between February 14 and March 1, 1991, were interviewed. No evidence of any operations other than that on February 14, 1991, was identified during the interview process.

The possibility of an unintentional operation of the breaker to 2-FCV-63-80, because of a confusion between Units 1 and 2, was evaluated. This possibility was considered because of the Unit 1 forced outage that occurred between February 18 and 26, 1991. No evidence was identified of an unintentional operation.

The Operations incident investigation team members performed a preliminary assessment and determined that the event was not reportable under 10 CFR 50.72. This determination was based upon the initial assumption that the event did not constitute a departure from the plant's design basis. As the investigation proceeded, a draft analysis of the event's safety implications was prepared by the incident investigation team. This draft analysis was sent to Nuclear Engineering (NE) for independent review.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Sequoyah Nuclear Plant Unit 2	0|5|0|0|0|3|2|8	9|1	0|0|3	0|0	0|5 OF 1|1

TEXT (If more space is required, use additional NRC Form 366A's) (17)

DESCRIPTION OF EVENT

On March 22, 1991, at 1646 EST after further investigation, it was determined that Unit 2 had operated in a condition outside the design basis during the time frame of February 14, 1991, to March 1, 1991, as a result of the breaker to 2-FCV-63-80 being in the locked closed position. The basis is that a single failure in the operator breaker or control circuit could cause the valve to inadvertently close, isolating the No. 3 CLA. Should this single failure occur following a Loss of Coolant Accident (LOCA), because of a rupture in RCS cold leg loops 1, 2, or 4, only two CLAs would be available for injection. The parameters used in the LOCA analysis of Section 15.3 and 15.4 of the UFSAR, requires three CLAs to be available for injection. This determination was based on consultation with Westinghouse Electric Corporation LOCA specialists. A one-hour notification phone call to the NRC was made in accordance with 10 CFR 50.72.(b)(1)(ii)(B) as a result of this determination at 1737 EST on March 22, 1991.

Upon further review, it was determined that the evolution performed would not achieve its intended function to further backseat check valve 63-624 by starting of the SIS pump. The leakrate for the primary check valve 63-562 (0.68 gpm) was evaluated to be greater than the leakrate for the secondary check valve 63-624 (0.21 gpm), using results from the leak rate testing performed before restart from the Cycle 4 refueling outage. The measured leakrate from testing at reduced pressure is extrapolated to a leakrate at full pressure conditions. The leakage from the RCS into the CLA through this header and not by other means had been previously determined as a result of extensive troubleshooting activities and by confirmation that water samples from both the CLA and RCS were very similar. The pipe header pressure between check valves 63-562, -624, -634 (RHR pump, loop 3 cold leg injection secondary check valve), and -555 (SIS pump, Loop 3 cold leg injection secondary check valve) is therefore considered to have very likely been at approximately 2,235 psig, normal RCS pressure at 100 percent reactor power. Therefore, when the upstream side of check valve 63-624 was vented to the holdup tank the differential pressure across 63-624 was approximately 2,235 psig. Starting of the 2A SIS pump pressurized the line between the pump and check valve 63-555 to approximately 1,500 psig. As indicated, the pressure in the line downstream of check valve 63-555 was approximately 2235 psig. Since the piping between check valves 63-561, -624, -634, and -555 was already at a pressure greater than the SIS discharge pressure, starting the SIS pump would not have applied any further pressure differential across 63-624. It was not recognized at the time the evolution was planned and performed that the downstream side of valve 63-555 was at a higher pressure than what the SIS pump could achieve.

Review of this evolution also considered whether starting of the SIP could have actuated the other three SIS secondary check valves 63-551, -553, and -557 for loops 1, 2, and 4, respectively, necessitating leakrate testing in accordance with SR 4.4.6.2.2.d. As designed, the minimum pressure downstream of these check valves, assuming no primary check valve leakage, would be approximately 600 psig, the pressure of the CLA. When the SIP was started with a 1,500 psig discharge pressure, a 900 psid could have been developed across the three SIS secondary check valves in the direction of the RCS.

DESCRIPTION OF EVENT

However, since water is incompressible and the piping between the primary and secondary check valves is water solid, the volume of water moved across the SIS check valves would be extremely small. If it is conservatively assumed that the CLA check valves (-622, -623, and -625) were leaking back to the CLAs (although there has been no indication of level or concentration changes), the most water that could have been moved across the SIS check valves would be approximately the leakrate of the CLA check valves measured during tests conducted at startup from the last refueling outage (on the order of 0.26 to 0.32 gpm). From this review it is concluded that the evolution did not result in actuation or "flow through the valve" as intended by SR 4.4.6.2.2.d and therefore testing to reverify check valve leakrate was not required.

As a result of further review of this evolution and the associated TS and design and licensing basis, it is concluded that the CLA isolation valve 2-FCV-63-80 should not have been closed. TS LCO 3.5.1.1, Action Statement "b" states: "With one cold leg injection accumulator inoperable due to the isolation valve being closed, either immediately open the isolation valve or be in HOT STANDBY within one hour and be in HOT SHUTDOWN within the next 12 hours." The corresponding bases states: "If a closed isolation valve cannot be immediately opened, the full capability of one accumulator is not available and prompt action is required to place the reactor in a mode where this capability is not required." The review of this TS action statement and bases by the involved Operations personnel, concluded that the isolation valve could be immediately opened and the action could be met by stationing individuals at the valve control and breaker to immediately reopen the valve in event of an accident, and by ensuring that the evolution was completed well within an hour. It was further reasoned that this evolution was less "severe" than the periodic accumulator drain and refill evolutions that were being necessitated by the check valve back-leakage. However, following further review of the technical specification action statement as written and the accident analysis, as further detailed in the analysis section, it is concluded that intentional closure of the isolation valves should not occur in Modes 1, 2, 3, and with pressurizer pressure above 1000 psig.

CAUSE OF EVENT

The direct cause of this event is attributed to inappropriate personnel actions in placing the breaker in the locked closed rather than the locked open position. The cause of that incorrect action could not be determined. Discussion with the ASOS indicated his belief that the breaker was locked open. A contributor to the event is lack of independent verification. Independent verification of manipulations of ECCS components is required by AI-37, however personnel believed that independent verification was not required given the process and procedures that were being used for this evolution.

AI-37 requires independent verification for the temporary alterations of removing and returning ECCS systems from and to service. AI-30 provides information relative to "system configuration control of CSSC safety related systems" and controls for implementing limited evolutions without formal procedures. AI-30 also refers to AI-58

TEXT (If more space is required, use additional NRC Form 366A's) (17)

CAUSE OF EVENT

for a detailed description of maintaining the alignment of these systems in accordance with their appropriate valve and power availability checklists. AI-58 lists exceptions to configuration log entries for specific activities including limited evolutions. Implementing the subject evolution in this manner eliminated the normal method of documenting independent verification and led the Operations personnel to believe that independent verification was not absolutely required. Additionally, the SOS had a high level of confidence in the performance of the involved ASOS.

The root cause of this event, however, is considered to be the judgement made that this activity constituted a limited evolution not requiring a procedure. While AI-30 provides flexibility for licensed personnel evaluation of the condition and therefore did not specifically prohibit this judgement, TVA considers that this activity should clearly have been recognized as being outside the scope of the limited evolution process. Further, when the P-11 interlock was encountered during the evolution this should have further indicated to the personnel involved that the activity was not a limited evolution and that a procedure was required. Had a procedure been prepared it is believed that the technical issues would have been appropriately identified and addressed. Additionally any evolution involving manipulation of ECCS components would have required written independent verification of return to normal. A contributing factor to the incorrect judgement is considered to be an inadequate preevolution review. The review performed consisted of review of the flow diagrams to assess the flow paths, the TSs, and peer review among several SROs. However the review did not include review of electrical, control or logic prints nor did it adequately assess TS and FSAR impact/significance. As a result of discussions concerning this evolution with Operations management and operating personnel it is concluded that inadequate training has been provided to ensure appropriate and consistent implementation of limited evolutions.

The error in the initial reportability determination is considered to have resulted from lack of engineering involvement in the assessment relative to design basis.

ANALYSIS OF EVENT

This event is being reported in accordance with 10 CFR 50.73, paragraph a.2.i, as an operation prohibited by TS 3.5.1.1 and 10 CFR 50.73, paragraph a.2.ii, as a condition that was outside the design basis of the plant.

With the breaker for the isolation valve locked closed (i.e., power to the valve), instead of locked open, a potential exists that a spurious active single failure in the control circuit could cause the valve to inadvertently close, isolating the No. 3 CLA. Locking open the operator breaker (i.e., power removed) prevents a spurious active single failure. Should this single failure occur following a large break LOCA because of a rupture in RCS cold leg Loops 1, 2, or 4; only two CLAs would be available for injection. The parameters in the LOCA analysis described in UFSAR, Section 15.4, requires three CLAs to be available for injection; assuming one of the four CLAs is lost to the sump through the break in the cold leg.

NRC Form 366A (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

Approved OMB No. 3150-0104 Expires 4/30/92

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Sequoyah Nuclear Plant Unit 2	0 5 0 0 0 3 2 8	9 1	— 0 0 3 —	0 0	0 8 OF 1 1

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ANALYSIS OF EVENT

An example of spurious active single failure is the unintended energizing of a power-operated valve to open or close. Spurious failures may occur independently of the component's environmental surroundings. Spurious operation is the change in equipment state because of electrically induced faults. Thus with power removed, no active failure of the valve may be postulated to occur. Upon swapover to recirculation from the sump, a passive failure may be assumed; however, the borated water in the CLAs would have already been discharged to the RCS. Therefore removing power assures three CLAs will be capable of injecting into the RCS, in the event of a RCS cold leg LOCA, and thus the design basis will be satisfied.

With the breaker to the operator of 2-FCV-63-80 locked closed, the postaccident peak clad temperature (PCT) could exceed the design limit, provided a large break LOCA occurs in the RCS cold leg pressure boundary piping loops 1, 2, or 4, and a single spurious failure is applied to 2-FCV-63-80 (valve fails to remain open), thus resulting in the elimination of one of the three remaining available CLA's. An additional train of ECCS (assumed to exist since the single failure occurred in the spurious actuation of 2-FCV-63-80) would be available, but would not supply sufficient flow to substitute for the loss of a CLA. This is because of the inability of the ECCS pumps to deliver the required volume of water (equal to or greater than an accumulator discharge) in the short time interval necessary. Because of the net loss in delivered flow, the time to resubmerge the bottom of the fuel after initial core uncovery, would be extended by more than 12 seconds and PCT could exceed the design limit.

SQN's Individual Plant Evaluation for COMPONENT FAILURE RATES generically documents failure rates for various type components in the plant. The failure rate for a motor operated valve (failure to remain in its normal position open or closed) is 1E-7/hour. An additional analysis showed that the conditional probability of a large break LOCA and one CLA motor operated isolation valve closing is negligible over a period of 14 days. The conditional probability of these two events, both occurring within a 14-day period, is 2.62E-10.

The limiting break size in terms of highest PCT for a small break LOCA is a 3-inch diameter break. The depressurization transient for this break is shown in UFSAR Figure 15.3.1-2. The extent to which the core is uncovered is shown in UFSAR Figure 15.3.1-3. For a small break LOCA and a failure of valve 2-FCV-63-80 to remain open, the PCT would not exceed 2,200 degrees F.

Beyond purely spurious failures, an evaluation was also conducted to determine whether closure of the isolation valve (which is not specifically environmentally qualified) could be expected to result from environmentally induced accident conditions. The results of this evaluation concluded that it is not expected that a harsh environment would cause spurious actuation and closure of 2-FCV-63-80 during the time period under which closure could adversely affect calculated PCT.

ANALYSIS OF EVENT

In review of the actual conditions over the subject period, it is noted that valve 2-FCV-63-80 remained open following this evolution during the time period the breaker was in the locked closed (power on) position (February 14 to March 1, 1991). The period of time that the valve was closed during the evolution was a short duration and positive controls were in place to immediately reopen the valve in event of an accident condition. There were no challenges to the ECCS during this time frame and no accumulator failures occurred. Isolation valve 2-FCV-63-80 is checked each shift to ensure that the valve is open in accordance with 2-SI-OPS-000-002.0, "Shift Log," which is required by TS SR 4.5.1.1.1. No deviations of the valve from the open position were identified during the approximate two week time frame.

Although the potential existed to challenge the design basis, there were no challenges to the ECCS or failures of 2-FCV-63-80, and therefore this event did not adversely affect the health and safety of the public.

CORRECTIVE ACTIONS

Immediate corrective action was to place the breaker for the operator for 2-FCV-63-80 in the locked open position.

The Plant Manager has discussed with the Operations personnel involved with this event the importance of performing independent verification for activities affecting nuclear safety. The Operations Superintendent has discussed with each of the Operations crews the circumstances of this event and the importance of performing independent verification in accordance with AI-37. Additionally the Operations personnel involved in this event will receive appropriate disciplinary action by April 19, 1991.

To provide interim controls until associated procedures are revised, a night order was issued by the Operations Superintendent to (1) require the Operations Superintendent's approval before performing a limited evolution (i.e., without a procedure) until further training is provided, (2) to require discussion with the Operations Superintendent if an unexpected response is encountered during a limited evolution and (3) to clarify that the independent verification requirements of AI-37 applies to component manipulations regardless of the AI-58 method that is used to control the configuration. Associated procedures will be revised to further clarify the need for independent verification by May 15, 1991.

While TVA believes that the subject activity should have been conducted with an approved procedure, TVA also believes there still remain certain simple manipulations involving deviations from normal configurations that should properly be considered operation of the facility rather than changes in the facility. For certain simple, short duration manipulations that will not require a bypass of permissives and for which direct positive control is maintained, generation of special procedures is not considered warranted and could impede reasonable facility operation. However TVA recognizes that these evolutions must be adequately and consistently controlled.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Sequoyah Nuclear Plant Unit 2	0|5|0|0|0|3|2|8	9|1	0|0|3	0|0	1|1 OF 1|1

TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTIONS

Additional criteria for evaluation and conduct of limited evolutions is being developed by TVA based on Operations management and personnel input, regulatory requirements, and input from other utilities. Bypassing of interlocks will be specifically disallowed under limited evolutions. A resultant training package is being prepared which will be provided to all licensed personnel. Additional guidance will be incorporated into associated procedures as appropriate. TVA is additionally evaluating whether an additional temporary procedure process should be established to handle activities/evolutions that are beyond the scope of limited evolutions but do not warrant development of a new formal procedure.

To provide clarification and promote consistency in future interpretation of TS 3.5.1.1, Action b, Operations management will review the position that intentional closure of the CLA isolation valves in Modes 1, 2, 3, and with pressurizer pressure above 1000 psig should not occur with licensed personnel.

TVA is additionally evaluating current processes/interfaces used to support initial reportability determinations, with particular reference to nuclear engineering involvement. This evaluation will be completed by April 15, 1991, and governing procedures/processes will be revised as appropriate.

ADDITIONAL INFORMATION

Previous mispositioning events were reviewed to determine if an event resulted from similar causes. None were identified such that corrective actions taken should have reasonably been expected to prevent this event.

Inspection Report Nos. 50-327/89-15, 50-328/89-15, and Notice of Violation 89-15-05 involved making a change to the facility as described in the FSAR without performing a written evaluation to determine whether the change involved an unreviewed safety question. The change involved taking the boron injection tank (BIT) out of continuous recirculation, resulting in the low flow alarm actuating and rendering the BIT inoperable. There was no procedure used to initially isolate BIT recirculation. Corrective action for this violation included a revision to AI-30 to define the conditions and controls under which manipulations can be performed without procedures. This revision was made with the intent to provide flexibility to address any number of unforseen simple scenarios, however, in hindsight, additional detail or training should have been provided to ensure appropriate and consistent implementation.

COMMITMENTS

1. Associated procedures will be revised to further clarify the need for independent verification by May 15, 1991.

COMMITMENTS

2. Additional criteria for evaluation and conduct of limited evolutions is being developed by TVA based on Operations management and personnel input, regulatory requirements, and input from other utilities. Bypassing of interlocks will be specifically disallowed under limited evolutions. A resultant training package is being prepared which will be provided to all licensed personnel by April 26, 1991.

3. Additional guidance (regarding limited evolutions) will be incorporated into associated procedures as appropriate by April 26, 1991.

4. To provide clarification and promote consistency in future interpretation of TS 3.5.1.1, Action b, Operations management will review the position that intentional closure of the CLA isolation valves should not occur with licensed personnel by April 19, 1991.

5. TVA is additionally evaluating current processes/interfaces used to support initial reportability determinations, with particular reference to nuclear engineering involvement. This evaluation will be completed by April 15, 1991.

6. Governing procedures/processes will be revised as appropriate as a result of commitment Number 5.

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

APR 25 1991

Docket Nos.: 50-327 and 50-328
License Nos.: DPR-77 and DPR-79

Tennessee Valley Authority
ATTN: Mr. D. A. Nauman
Senior Vice President,
Nuclear Power
6N 38A Lookout Place
1101 Market Square
Chattanooga, TN 37402-2801

Gentlemen:

SUBJECT: NOTICE OF VIOLATION
(NRC INSPECTION REPORT NOS. 50-327/91-06 AND 50-328/91-06)

This refers to the inspection conducted by P. Harmon of this office on March 6 - April 5, 1991. The inspection included a review of activities authorized for your Sequoyah facility. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed inspection report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Based on the results of this inspection, certain of your activities appear to violate NRC requirements, as specified in the enclosed Notice of Violation. We are concerned about this violation because independent verification is a very important step in providing adequate assurance that critical safety systems will carry out their intended function. This concern is amplified by a recently reported additional example of lack of adequate second party verification that contributed to a carbon dioxide fire suppression system being inoperable for a year. In addition, we are concerned with other aspects of the operators' performance during this event including performing a non-routine evolution without a written procedure and bypassing a protective grade interlock without a detailed review. Please include a discussion of these issues with your response to the violation. Because of these events and concerns we are not exercising discretion as allowed by Section V.G.1. of the Enforcement Policy even though the events were identified and reported by TVA.

Two additional examples of apparent violation 50-327, 328/91-04-01 were identified where operators failed to properly acknowledge control room alarms as required by AI-30. An Enforcement Conference was held on April 12, 1991 concerning operator responsiveness to alarms as described in Inspection Report 50-327, 328/91-04 and the two examples described in this report were noted in

9105080077

that conference. Consequently, these additional examples will be considered in our deliberations to determine the appropriate enforcement actions for operators failing to properly respond to control room alarms.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and any additional actions you plan to prevent recurrence. After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

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

The responses directed by this letter and its enclosures are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, PL 96-511.

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

Sincerely,

Bruce A. Wilson

Bruce A. Wilson, Chief
TVA Projects

Enclosures:
1. Notice of Violation
2. NRC Inspection Report

cc w/encls: (See page 3)

cc w/encls:
M. Runyon, Chairman
Tennessee Valley Authority
ET 12A 7A
400 West Summit Hill Drive
Knoxville, TN 37902

J. B. Waters, Director
Tennessee Valley Authority
ET 12A 9A
400 West Summit Hill Drive
Knoxville, TN 37902

W. F. Willis
Chief Operating Officer
ET 12B 16B
400 West Summit Hill Drive
Knoxville, TN 37902

D. Nunn, Vice President
Nuclear Projects
Tennessee Valley Authority
1101 Market Street
6A Lookout Place
Chattanooga, TN 37402-2801

Dr. M. O. Medford
Vice President, Nuclear Assurance,
Licensing and Fuels
Tennessee Valley Authority
6N 38A Lookout Place
Chattanooga, TN 37402-2801

County Judge
Hamilton County Courthouse
Chattanooga, TN 37402

R. Beecken, Plant Manager
Sequoyah Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Soddy-Daisy, TN 37379

E. G. Wallace, Manager
Nuclear Licensing and
Regulatory Affairs
Tennessee Valley Authority
5N 157B Lookout Place
Chattanooga, TN 37402-2801

M. Cooper
Site Licensing Manager
Sequoyah Nuclear Plant
P. O. Box 2000
Soddy-Daisy, TN 37379

TVA Representative
Rockville Office
11921 Rockville Pike
Suite 402
Rockville, MD 20852

General Counsel
Tennessee Valley Authority
400 West Summit Hill Drive
ET 11B 33H
Knoxville, TN 37902

Michael H. Mobley, Director
Division of Radiological Health
T.E.R.R.A. Building, 6th Floor
150 -9th Avenue North
Nashville, TN 37247-3201

J. Wilson, Site Vice President
Sequoyah Nuclear Plant
Tennessee Valley Authority
P. O. Box 2000
Soddy-Daisy, TN 37379

State of Tennessee

ENCLOSURE 1

NOTICE OF VIOLATION

Tennessee Valley Authority
Sequoyah

Docket Nos. 50-327, 50-328
License Nos. DPR-77, DPR-79

During the Nuclear Regulatory Commission (NRC) inspection conducted March 6, 1991, through April 5, 1991, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1990), the violation is listed below:

> Technical Specification 6.8.1 requires that procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, be established, implemented and maintained. This includes maintenance, operating, surveillance, administrative, and fuel handling procedures. The requirements of TS 6.8.1 are implemented in part by Administrative Instruction AI-37, Independent Verification, section 6.1.2 which states that breakers in the Emergency Core Cooling System shall be independently verified to be in the correct position/condition when the system or component is being returned to service or restored to a standby line-up.
>
> Contrary to the above, on February 14, 1991, the breaker for the Unit 2, Number 3 cold leg accumulator isolation valve was manipulated during a non-routine evolution, without performance of any independent verification as required by AI-37, Independent Verification. This resulted in the breaker being left in the energized condition during plant operation contrary to the FSAR design basis.
>
> This is a Severity Level IV violation (Supplement I)

Pursuant to the provisions of 10 CFR 2.201, Tennessee Valley Authority is hereby required to submit a written statement or explanation to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555, with a copy to the Regional Administrator, Region II, and a copy to the NRC Resident Inspector, Sequoyah, within 30 days of the date of the letter transmitting this Notice. This reply should be clearly marked as a "Reply to a Notice of Violation" and should include [for each violation]: (1) the reason for the violation if admitted, (2) the corrective steps which have been taken and the results achieved, (3) the corrective steps which will be taken to avoid further violations, and (4) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an

9105080088

order may be issued to show cause why the license should not be modified, suspended, or revoked or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

THE NUCLEAR REGULATORY COMMISSION

Bruce A. Wilson

Bruce A. Wilson, Chief
TVA Projects

Dated at Atlanta, Georgia
this 25th day of April 1991

(Closed) LER 328/89-13, Incorrect Smoke Detectors Located in Unit 2 Annulus Fire Zone 374 Due to Personnel Error.

The event involved the installation of three ionization detectors instead of photoelectric-type devices. TS 3.3.3.8, Table 3.3-11 requires 20 photoelectric detectors to be operable in the subject fire zone. However, due to the incorrect replacement only 19 were installed and operable. The investigation determined two of the detectors were replaced in 1985 and the other replacement was unable to be established. In the time frame of the replacements, craftsmen had the responsibility for identification of the correct replacement part. The WR program at this time, as described in Sequoyah Standard Practice SQM2 gives planners the responsibility for identification of the proper replacement part. Six other fire zones were inspected to determine if any other incorrect type detectors were installed. No other problems were identified. The inspector reviewed the corrective actions and the LER closeout package. This LER is closed.

8. Event Follow-up (93702)

On March 1, 1991 at 1:27 a.m. the breaker for the motor operator on the Unit 2 no. 3 cold leg accumulator isolation valve was found locked in the closed position. The isolation valve, 2-FCV-63-80, was open. Discovery of the closed breaker was made during performance of monthly surveillance SI-OPS-063-013.0, CLA Valves Power Removal Verification. Upon discovery of the closed breaker, operators removed power and the breaker was locked in the open position at 1:31 a.m.

An incident investigation into the event determined that the 2-FCV-63-80 operator breaker was manipulated on February 14, 1991 as part of an evolution performed to reduce the inleakage to the #3 accumulator. The evolution required the temporary closure of the isolation valve, via the motor operator, in an attempt to seat the leaking check valve for that accumulator. The breaker for the valve was energized and the valve closed, but an interlock, permissive P-11, actuated to reopen the valve immediately. P-11 operates to automatically open the isolation valves for the accumulator whenever RCS pressure is above 1970 psig. Operators reviewed the logic circuitry and determined that the P-11 interlock had in fact reopened the valve. A decision was then made to close the valve, and then immediately open the breaker to prevent the interlock from reopening the valve. This was done successfully, but without written procedures. After the evolution was completed, power was restored to the breaker and the valve was reopened. The ASOS performing the evolution at the breaker then was required to remove power from the breaker and lock the breaker open. The ASOS stated in later interviews that he was positive that he had reopened the breaker and locked it in the open position. The event investigation concluded that he had mistakenly locked the breaker in the closed (energized) position.

Several issues of concern were identified for this event:

- Operators did not provide independent verification of the position of the breaker as required by AI 37, Independent Verification.

- Non-routine evolutions were performed without written procedures.

- The Protective Grade interlock, P-11, was defeated by opening the breaker when the isolation valve was closed without adequate review on the part of the Operations crew.

As the investigation into the event continued, the licensee determined, on March 22, 1991 that due to the breaker being energized, the plant had been operating in an area outside the FSAR design basis from February 14 until March 1, 1991.

The isolation valve is required to be open to meet the requirements of TS 3.5.1.1 for operability of the cold leg accumulators. TS surveillance requirement 4.5.1.1.1.c requires that each cold leg accumulator shall be demonstrated operable "At least once every 31 days when the RCS pressure is above 2000 psig by verifying that power to the isolation valve operator is disconnected by removal of the breaker from the circuit."

The TS Basis describes the reason for the requirements to remove power to the valve operator. Basis 3/4.5.1, Accumulators, states that "The accumulator power operated isolation valves are considered to be operating bypasses in the context of IEEE std. 279-1971, which requires that bypasses of a protective function be removed automatically whenever permissible conditions are not met. In addition, as these accumulator isolation valves fail to meet single failure criteria, removal of power to the valves is required." The concern articulated in the basis is that a single failure in the operator breaker or its control circuit could cause the isolation valve to inadvertently shut, causing the loss of the accumulator during the postulated accident.

The various issues in this event were still under investigation by the licensee at the end of the reporting period and will be addressed in a final Incident Investigation and a LER.

The inspector noted that there were elements of this event which were similar to the Boron Injection Tank event described in IR 50-327,328/89-15. Both involved manipulation of ECCS equipment without approved procedures.

AI-37, Independent Verification, section 6.1.2 states that breakers in the Emergency Core Cooling System shall be independently verified to be in the correct position/condition when the system or component is being returned to service or restored to a standby line-up. Failure of the operating crew to follow the requirements of AI-37, Independent Verification is a violation and will be tracked as VIO 50-327,328/91-06-01.

9. Exit Interview (30703)

The inspection scope and findings were summarized on April 9 and 15, 1991, with those persons indicated in paragraph 1. The Senior Resident Inspector described the areas inspected and discussed in detail the inspection findings listed below. The licensee acknowledged the inspection findings and did not identify as proprietary any of the material reviewed by the inspectors during the inspection.

Inspection Findings:

One violation was identified.

VIO 327,328/91-06-01, Failure to Follow Requirements of AI-37, Independent Verifications for Accumulator Isolation Valve Breaker.

Two additional examples of a previous violation (91-04-01) involving operators failing to follow the requirements of AI-30, Conduct of Operations, in responding to alarms were identified.

The actions taken during a turbine runback and subsequent actuation of a rod insertion limit alarm were discussed. The Operations Supervisor agreed to review and revise the Annunciator Response Instruction and provide additional training for operators for responding to this alarm.

TVA staff response to a reactor coolant pump oil leak was considered thorough and measured, with the proper safety consciousness applied to restore the oil level without a plant shutdown. A strength was noted in the ALARA preplan and radcon coverage for the necessary containment entries.

During the reporting period, frequent discussions were held with the Site Director, Plant Manager and other managers concerning inspection findings.

The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

10. List of Acronyms and Initialisms

AHU - Air Handling Unit
AI - Administrative Instruction
ALARA - As Low As Reasonably Achievable