UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W., SUITE 3100
ATLANTA, GEORGIA 30303

Report Nos. 50-324/81-12 and 50-325/81-12

Licensee: Carol'na Power and Light Company
411 Fayetteville Street
Raleigh, NC 27602

Facility Name: Brunswick

Docket Nos. 50-324 and 50-325

Licensee Nos. DPR-62 and DPR-71

Inspection at Brunswick site near Wilmington, NC

Inspectors: Ross Butcher for D. F. Johnson, Senior Resident Inspector — 6-26-81 Date Signed

Ross Butcher for L. W. Garner, Resident Inspector — 6-26-81 Date Signed

Approved by: C. A. Julian, C. A. Julian, Acting Section Chief, Division of Resident and Reactor Project Inspection — 6-30-81 Date Signed

SUMMARY

Inspection on May 15 - June 15, 1981

Areas Inspected

This routine inspection involved 158 resident inspectors hours on site in the area of plant operations; operational safety verification; follow-up on licensee event reports; plant tours; licensee action on previous inspection findings; follow-up on TMI Task Action Plan items; review of periodic reports; monitoring plant safety review committee meetings; and independent inspection efforts.

Results

Of the 9 areas inspected, no violations or deviations were identified.

DETAILS

1. Persons Contacted

Licensee Employees

B. Furr, Vice President, Nuclear Operations
C. Dietz, General Manager, Brunswick
*A. Bishop, Engineering Supervisor
G. Bishop, Project Engineer
*S. Bohanan, Principal Specialist Regulatory Compliance
*J. Boone, Project Engineer
J. Brown, Manager, Operations
J. Dimmette, Mechanical Maintenance Supervisor
M. Hill, Maintenance Manager
R. Morgan, Plant Operations Manager
*G. Oliver, E & RC Manager
A. Padgett, Assistant to General Manager
G. Peeler, Shift Operating Supervisor
R. Poulk, Regulatory Specialist
W. Triplett, Administrative Manager
*W. Tucker, Technical and Administrative Manager

Other licensee employees contacted included technicians, operators and engineering staff personnel.

*Attended exit interview

2. The inspection scope and findings were summarized on June 12, 1981, with those persons indicated in Paragraph 1 above. Meetings were also held with senior facility management periodically during the course of this inspection to discuss the inspection scope and findings.

3. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptab or may involve a violation. New unresolved items identified during this inspection are discussed in paragraph 5.

4. Licensee Action on Previous Inspection Findings

(Closed) Inspector Followup Items (324/81-06-05 and 325/81-06-07). The inspector's review of LER's for the period of March 15 through June 15, 1981, have indicated a definite trend toward improvement in the quality of LER's submitted during this time frame. The LER's reviewed provided an accurate and complete description of reactor operational events, including corrective actions to prevent recurrence.

(Closed) Unresolved Item (325/81-06-02). Alarm Masking on Commmon Annunciators. Procedure OI-5A has been issued to define safety-related annunciators which monitor the same condition on several different components. The procedure provides instructions for controlling the removal and returning to service of that portion of the circuit associated with a malfunctioning component.

(Closed) Unresolved Items (324/81-11-02 and 325/81-11-03). The licensee inspected and cleaned, as applicable, all control room electrical panels and instructed personnel in the requirements of Admini trative Instruction AI-17 "Plant Housekeeping" and Administrative Procedure, Section 4.1.18 "Control Room Housekeeping".

5. Reportable Occurrences

The below listed Licensee Event Reports (LER's) were reviewed to determine if the information provided met NRC reporting requirements. The determination included adequacy of event description and corrective action taken or planned, existence of potential generic problems and the relative safety significance of each event. Additional in-plant reviews and discussions with plant personnel, as appropriate, were conducted for those reports indicated by an asterisk.

Unit 1

Supplement 1-80-38 (3L)	1A Reactor Recirculation Pump Tripped
Supplement 1-80-67 (3L)	Erroneous rod blocks received from rod worth minimizer (RWM) system for rods pulled from groups between No. 18 and 30.
*1-81-32 (3L)	1B RHR heat exchanger, Model No. CEU, Size 52-8-144, baffle plate partially bowed in center at bottom.
1-81-37 (3L)	Monthly HPCI System Component Test, PT 9.3a. had not been performed in February 1981.
1-81-41 (3L)	Primary Containment Atmospheric Monitor Oxygen Analyzer, 1-CAC-ATH-1259-2, Model No. F3M3-1AX, tripped.
1-81-44 (3L)	Drywell Oxygen Concentration Analyzer, 1-CAC-AT-1259-2, inoperable.

Unit 2

Supplement
2-80-102 (3L) When rod 26-35 is fully withdrawn, "Full Out" position indication could not be acheived.

2-81-14 (3L) Vacuum breaker butterfly valve, 2-CAC-V17, declared inoperable.

2-81-21 (3L) Reactor coolant conductivity greater than 2 umho/cm^2.

2-81-29 (3L) HPCI system injection valve, 2-E41-F006, would not open from RTGB.

2-81-43 (3L) Primary Containment Atmospheric Monitor Oxygen Analyzer 2-CAC-ATH-1259-2, Model No. F3m3-1AX, declared inoperable.

2-81-45 (3L) Reactor coolant analysis revealed vessel conductivity exceeded specifications and scram initiated.

2-81-46 (3L) "Rod Overtravel" annunciator received for Rod 30-23. This rod and rods symmetric to it, inserted and deactivated.

2-81-47 (3L) Reactor coolant conductivity greater than 2 umho/cm^2.

*2-81-49 (1T) Inspection of Unit 2 heat exchangers, Type CEU, Size 52-8-144, revealed partial displacement of 2B heat exchanger divider plate.

LER 1-81-32 (3L)

With Unit 1 shutdown, during the inspection of 1B RHR heat exchanger, on April 19, 1981, it was found that the heat exchanger baffle plate was displaced approximately 9" at the bottom, which created a service water flow path from the inlet to the outlet, bypassing the tubes. The purpose of the plate is to separate RHRSW entering the heat exchanger from RHRSW leaving after it has passed through the heat exchanger U-tubes. From the inspection and an engineering evaluation of the plate failure, it was concluded that the failure occurred due to the failure of plate attachment welds to within 8-10" of the heat exchanger tube sheet which resulted from excessive differential pressure across the plate. The cause of the excessive differential pressure has been attributed to a blockage of the heat exchanger tube by shells (approximately 95% oyster) which accumulated in the heat exchanger when shells on the walls of the main service water piping became dislodged. The shell buildup apparently resulted from the service water chlorination system being out of service for an extended period.

During the repair of the 1B RHR heat exchanger, a loss of cooling was experienced immediately following the starting of a second RHR service water pump on the 1A RHR heat exchanger. In establishing an alternate shutdown cooling lineup, it was decided to remove water from the vessel with the RHR system through the fuel pool coolers and to the condensate storage tank (CST). To return water to the vessel, the Core Spray system would take a suction from the CST and provide makeup to the vessel at a throttled flow of approximately 5000 gpm for level control. This lineup was later modified to delete the Core Spray system and the CST and return water to the vessel using the RHR system. Vessel temperature never reached 170°F. Using the Control Rod Drive system for vessel return was considered, however, it was felt that the low flow rate of this system would not provide sufficient cooling and mixing to maintain reactor temperature below a desirable level.

To restore a normal shutdown cooling lineup as expeditiously as possible, temporary repairs were performed on the 1A heat exchanger and it was restored to service while permanent repairs were still in progress on the 1B heat exchanger. The baffle plate on the 1A heat exchanger was also found to be displaced at the bottom.

An evaluation of the 1A heat exchanger baffle failure concluded that baffle displacement also occurred as a result of shell buildup. When the second RHRSW pump was started, increased flow through the heat exchanger caused an excessive differential pressure that displaced the baffle plate approximately 9". Permanent repairs for the 1A heat exchanger will follow the completion of work and the return to service of the 1B heat exchanger.

A program is being pursued to monitor safety-related heat exchanger performence. It will consist of using available temperature, flow and differential pressure instrumentation to determine the heat transfer rates and flow rates. This will help predict baffle plate degradation.

In order to prevent possible water hammer occurrences, plant procedures will be revised to ensure the RHRSW system header is vented once per week and prior to operation of the system. In addition, the heat exchanger tubes and service water piping will be cleaned to remove shell buildup. A design review of the divider plate will be performed to assure its adequacy. These actions, along with the resumption of the service water chlorination program, will help eliminate future organism shell growth.

This is an unresolved item pending completion of the licensee's actions 50-325/81-12-01.

LER 2-81-49 (1T)

With Unit 2 at power, an evaluation, based on indications of heat exchanger tube obstructions found during inspections of the Unit No. 1 RHR heat exchangers, was performed on the Unit No. 2 RHR heat exchangers to ascertain their operability. Information concerning the condition of the RHR 2B heat exchanger was obtained using ultrasonic and differential pressure testing. Both methods gave indications of divider plate damage. The lower head was then removed to obtain verification of the damage.

The divider plate separates the service water influent from effluent in the RHR heat exchanger below the tube sheet. The top of the divider plate is welded to the tube sheet, both sides are welded to the water box walls, and the bottom fits into a groove in the water box cover. The divider plate is 1" thick x 44 3/4" high x 54" wide and is made of SB-402, Alloy 715 (70-30 Cu-Ni) material.

The divider plate was found buckled in the center at the bottom where it fits in the groove in the water box cover, and was displaced approximately 3 inches at the bottom center of the divider plate. The deflection started approximately 3 inches from one side and 9 inches from the other. The welds along the top and sides of the plate remained intact (the plate was previously replaced in April 1980, reference LER 2-80-30).

Shells of various sizes were found on the inlet side and formed a layer averaging 2 inches in thickness with areas as much as 5 inches thick. Additional shell blockage was also found inside approximately 50% of the tubes.

Examination of RHR heat exchanger 2A using the ultrasonic test technique determined that the divider plate was intact with no displacement. Differential pressure tests, however, detected excessive dp's at design flow rates, and so RHR service subsystem 2A was also declared inoperable. Unit 2 was then shutdown as required by the Technical Specifications. The bottom head of the 2A heat exchanger was removed and the baffle plate was found to be intact as indicated by the ultrasonic test. Shells of various sizes were found on the inlet side of the heat exchanger, and formed a layer approximately ¼" to ½" thick. Additional shell blockage was also found inside affecting approximately 60% of the tubes.

An evaluation of design and operating data determined that shells found in the 2B heat exchanger had blocked and obstructed tubes, producing excessive differential pressures across the divider plate during the operation of an RHR service water pump. These differential pressures produced stresses greater than the divider plate could withstand, causing it to bow to the as found condition.

The presence of shells in the heat exchanger resulted from a buildup of oyster shells on the walls of the main service water piping. As the oysters died, their shells fell off and slowly collected in the heat exchanger. The oyster buildup resulted from the chlorination system being out of service for an extended period due to operating difficulties.

The high dp on the 2A RHR heat exchanger was the result of shells found in the heat exchanger that had blocked and obstructed tubes (as in the 2B heat exchanger). The shell buildup was not as extensive as in the 2B heat exchanger due to its more infrequent use. With fewer shells, the differential pressures during pump operation were not sufficient to cause divider plate deformation. The shells were removed from the water box and the tubes were cleared to remove all obstructions in both heat exchangers. The divider plate of 2B is currently being repaired.

A review was made of the service water venting procedure, vent location, and piping arrangement to determine if problem areas existed, which could lead to a water hammer. None were found. The piping itself was also inspected for evidence of water hammer damage or movement, and none was found.

An evaluation and inspection was performed on all other safety-related loads cooled by service water to verify that the necessary cooling capability existed. All the D/G heat exchangers were inspected as they see frequent service. While a limited amount of shells were found, the volume had no impact on the cooling capability.

Random inspection or reviews of recent inspections were performed on the other safety-related heat exchangers. All of these see infrequent service, and so there would not have been the opportunity for a gradual buildup of shells. No shell buildup problems were identified.

ACTION TO PREVENT RECURRENCE:

a. PT 8.1.4 will be revised to include as a prerequisite that the RHR service water headers have been verified full by venting.

b. The tubes in all the heat exchangers will be cleaned to remove obstructions.

c. A design review of the divider plate adequacy will be made.

d. Service water piping will be cleaned as necessary to ensure that shell blockage from existing growth on the piping will not endanger the performance of safety-related heat exchangers.

e. The clorination of service water will be reinitiated to prevent future shell growth.

f. The RHR heat exchangers will be monitored for shell buildup to ensure that divider plate stresses are maintained acceptably low.

g. Existing periodic inspection procedures for safety-related service water cooled heat exchangers will be reviewed to assure that they are adequate.

This is an unresolved item pending completion of the licensee's actions, 50-324/81-12-01.

6. TMI Action Plan Requirements

I.A.1.3., Shift Manning

a. In letters submitted by the licensee on November 5, 1980, and December 15, 1980, it was stated that the Brunswick facility meets the shift manning requirements outlined in D. G. Eisenhut's letter of July 31, 1980, and shift manning requirements of Task Action Plan Item I.A.1.3 of NUREG-0737.

   Table 6.2.2-1 of the Technical Specification specify the minimum shift crew composition at the Brunswick facility. During review of this item, certain ambiguities were recognized in the Technical Specification Tables 6.2.2-1 for both units. Region II and representatives of NRR were informed of this matter. These ambiguities appear to be due to typographical errors made during recent Technical Specification changes. The licensee has agreed to request a Technical Specification change to correct these errors. The Technical Specifications meet the minimum shift staffing requirements of NUREG-0737.

b. In addition, the licensee has established administrative procedure 4.1.1., which specifies a normal shift composition which exceeds the minimum requirement. It states in part, "Each operating shift with fuel in both Unit Nos. 1 and 2 reactor vessels, normally consists of a Shift Operating Supervisor, Shift Foreman, a senior licensed Control Operator, three operator licensed Control Operators, and four Auxiliary Operators."

c. The licensee submitted, in a letter dated February 26, 1981, further clarification of their position on restrictions on the use of overtime for plant staff members who perform safety-related functions. The following is a summary of CP&L's position on this matter:

   While CP&L agrees with the concept of limiting overtime for key personnel to the extent possible, the restrictions proposed by Item I.A.1.3 could result in significant scheduling confusion and could create hardships for some operators by requiring them to work odd hours. The operators at Brunswick work an eight-hour rotating shift schedule. Each shift lasts seven days. The operator's week, for pay purposes, begins and ends at midnight each Friday. The schedule is designed to give the operator a 40-hour work week, however, the large increase in training requirements and the changes in staffing requirements, do not always permit scheduling which is compatible with rigid restrictions of Item I.A.1.3. The individual restrictions of Item I.A.1.3. are addressed below:

NRC Position

(1) An individual should not be permitted to work more than twelve hours straight (not including shift turnover time).

(2) There should be a break of twelve hours (which can include shift turnover time) between all work periods.

(3) An individual should not work more than seventy-two hours in a seven-day period.

(4) An individual should not be required to work more than 14 consecutive days without having two consecutive days off.

CP&L's overtime policy for licensed operators, STAs and key safety personnel is summarized as follows:

(1) An individual shall not be permitted to work more than 12 hours straight (not including shift turnover time).

(2) An individual will have at least the same number of hours off between work periods as the length of his last work period (not including shift turnover time).

(3) An individual shall not work more than 84 hours in any seven-day period (not including shift turnover time).

(4) An individual shall not work more than 14 consecutive days without having two consecutive days off.

These limitations apply when the Reactor Coolant System is greater than 200°F and when fuel is being moved within the reactor pressure vessel. Deviations from the above limitations must be approved by senior plant management with appropriate documentation of the circumstances requiring the deviation.

For the reasons explained in their letter, CP&L believes that the normal facility manning policies meet the intent of the guidance contained in NUREG-0737 for normal operating conditions and that additional formal limits would only create an extreme additional administrative burden without an improvement in safety.

The licensee has established administrative procedures that promulgates the above criteria for limitations on overtime required of licensed operators. The policy established appears to be in the best interest of the public health and safety and operator morale. This continuing policy appears to adequately resolve concerns expressed in Eisenhut's letter of July 31, 1980, and NUREG-0737. It appears that CP&L's response and actions satisfactorily meet the requirements of NUREG-0737 in this area.

I.C.6., Guidance on Procedures for Verifying Correct Performance of Operating Activities

a. CP&L's commitments on this item are as follows.

I.C.6. gives ANS 3.2 with five supplemental provisions as an example of an acceptable program to meet the requirement. The program at the Brunswick Plant meets the requirements of ANSI 18.7-1976 (ANS 3.2). The Brunswick Plant has taken the following action to meet the requirements of the five supplemental provisions:

-- The Plant Operating Manual will be revised to require the surveillance testing program to meet the requirements of ANSI 18.7-1976, Section 5.2.6, and this provision. The requirements are being met, currently, but the Operating Manual must be revised to require the controls of 5.2.6;

-- Supplemental Provision 2 is currently a requirement of the Brunswick Plant Program;

-- Verification by a second qualified person is required when placing equipment under clearance. The second person is the one accepting the clearance. A second qualified person verifies equipment is returned to service properly;

-- Supplemental Provision 4 will be properly covered when the requirements for Supplemental Provision 1 are added to the Plant Operating Manual;

-- When returning equipment to service which has not been under clearance, for example, instruments or hydraulic snubbers removed for surveillance testing, a second person will verify proper system alignment unless functional testing can be performed without compromising plant safety, and can prove that all equipment, valves, and switches involved in the activity are currently aligned. The person performing the verification will have the qualifications necessary for returning the equipment to service or will be a QA inspector.

b. The licensee completed the revisions to the Plant Operating Manual on April 3, 1981. The inspectors reviewed the licensee's actions with respect to the above commitments in the following areas:

-- Plant Operating Manual, Volume 1, Section 7.0, "Periodic Testing", has been revised to include the guidance of ANSI 18.7-1976 in the area of surveillance testing (Supplemental Provision 1);

-- Plant Operating Manual, Volume 1, Section 11.5, "Clearances", designates the shift foreman (SRO) as the responsible person for releasing systems and equipment for maintenance or surveillance testing and return to service (Supplemental Provision 1);

-- Plant Operating Manual, Volume 1, Section 11.5, "Clearances", assigns responsibility for equipment control to the shift foreman (SRO) and the qualified person accepting the clearance (Supplemental Provision 3);

-- Plant Operating Manual, Volume 1, Section 11.5.1.c, contains provisions to assure that control room operators are informed of changes in equipment status and the effects of such changes (Supplemental Provision 4);

-- Plant Operating Manual, Section 7.0, states, when returning equipment to service, a qualified second person will verify the proper system alignment, unless functional testing can be performed without compromising plant safety and other means can prove that all equipment, valves and switches involved in the activity are correctly aligned (Supplemental Provision 5).

Results of the inspector's review of the above procedures, indicate that all the items listed in position I.C.6, appear to be satisfied.

I.C.5., Procedures for Feedback of Operating Experience to Plant Staff

The licensee has prepared the following procedures in response to Item I.C.5. Administrative Instruction A1-02, "Feedback of Operating Experience", establishes a program to ensure appropriate information is provided to all personnel. Its purpose is to establish a program that ensures appropriate information obtained from the review of operating experience information is reviewed and evaluated in a timely manner and provided to all licensed personnel and other personnel as appropriate and to perform trend analysis by review of BSEP LER"s, Q-list trouble tickets and NPRD reports. The plant General Manager is responsible for the implementation of this program. The Principal Engineer, On-Site Nuclear Safety (ONS), is responsible for the initial screening of the documents, coordinating the evaluations, and preparing the

Operating Experience Feedback (OEF). Follow-up will be made by ONS to ensure that appropriate action is taken. The shift engineers (STA) are responsible for performing the trend analysis review and issuing the periodic trend analysis report.

Onsite Nuclear Safety Instruction No. 1, "Operating Experience Feedback", establishes responsibilities for assuring that pertinent information is continually supplied to the operating and training organizations. The purpose of this instruction is to establish ONS responsibilities for assuring that operating information pertinent to plant safety is continually supplied to the operating and training organizations. ONS will perform the review and feedback of pertinent operational information originating both within and outside the Company.

Corporate Nuclear Safety Instruction No. 9, "Operating Experience Feedback", establishes corporate responsibilities for assessment of operating experiences outside the facility. The purpose of this instruction is to establish CNS responsibilities and guidelines for carrying out a portion of the operating experience assessment function required by NRC "Action Plan" (NUREG-0660), Item I.C.5. CNS will perform the review and feedback of pertinent operational information originating outside of the Company organization. Specifically excluded are NRC Bulletins and Orders issues which will be handled on-site.

Results of the inspectors review of the above procedures indicate that all the items listed in position I.C.5 appear to be satisfied.

II.K.3.22, Automatic Switchover of Reactor Core Isolation Cooling System Suction - Verify Procedures and Modify Design

NUREG-0737 states that the reactor core isolation cooling (RCIC) system takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. This switchover should be made automatically. Until the automatic switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

In a letter to Eisenhut submitted on December 15, 1980, the licensee stated that modifying RCIC to provide for auto-switchover of pump suction from the condensate tank to the suppression pool will require

RCIC to be removed from service. The licensee has elected to perform this modification during the following scheduled outages:

Unit 2 - Late 1981
Unit 1 - Early 1982

Since the switchover is currently addressed in plant operating procedure OP-16, "RCIC System" and can be performed from the control room, the licensee does not feel that the modification warrants the reduction in safety margin associated with doing the modification while operating with the RCIC out of service.

This item remains open pending licensee's actions.

Item I.A 1.1, Shift Technical Advisor

In response to NUREG-0737, Item I.A.1.1, Shift Technical Advisor (STA), Brunswick has provided on duty STAs.

The STA duties are separated into two distinct functional responsibilities. They are (1) operating experience assessment and (2) accident assessment. Both functions are performed by the STA group to ensure proper understanding of the two functions by all individuals (STA) involved. This is accomplished by assignment of STA personnel on a scheduled rotating basis.

The operating experience assessment function provides additional capability, dedicated to concern for the safety of the plant, to perform engineering evaluations of plant operations. A portion of the STA group at any one time is a dedicated day-shift function and receives training in normal and off normal operations. The accident assessment function provides additional capability, dedicated to the concern for safety of the plant, and for diagnosis of off normal events. This function of the group is available on shift to augment the operating shift as required. The individual(s) who perform this function have other nonaccident duties related to plant safety.

The STAs are B.S. Degreed Engineers trained in normal and off normal operations. Retraining will be conducted annually. The group will remain cognizant of current operating experience evolutions through the operating experience assessment functions. They will have no other direct operating duties that might detract from their STA duties when performing this function.

The Shift Technical Advisors are available on site for both the operating experience and accident assessment functions. Assignment during the accident assessment function includes periods where the STA is on site but not restricted to the control room. Being on site, the STA will be capable of responding to an emergency situation within ten minutes of being alerted by the shift supervisor.

Full implementation and compliance of the requirements for STA Training set forth in NUREG-0578, as clarified or modified by D. G. Eisenhut's letter of September 13, 1979, H. R. Denton's letter of October 30, 1979, D. G. Eisenhut's letter to Mr. T. D. Keenan of November 14, 1979, NUREG-0660 and NUREG-0737 appears to have been accomplished. The inspector had no further questions in this area.

Item II.B.4 - Training for Mitigating Core Damage

NRC Position:

Licensees with operating reactors will develop a training program by January 1, 1981, and initiate the training program by April 1, 1981. The initial program should be completed by October 1, 1981.

CP&L Response:

The licensee has prepared a study guide and associated lesson plans that meet the criteria defined in H. R. Denton's March 28, 1980 letter and NUREG-0737. This program was implemented on March 28, 1981, attended by six reactor operators to serve as a pilot course. The training program has been subsequently revised as a result of evaluation of the initial pilot program and rescheduled for the week of June 8, 1981. Subsequent training sessions have been scheduled throughout June, July and August to include the remainder of the personnel as required by NUREG-0737.

This is an IFI item pending completion of the above training sessions. (324/81-12-03 and 325/81-12-03).

Item II.E.4.2 - Containment Isolation Dependability

Position 5 of NUREG-0737 requests justification of the containment pressure isolation setpoint. The primary containment (drywell) pressure isolation setpoint for the Brunswick Steam Electric Plant, Units 1 and 2 is equal to or less than 2.0 psig. CP&L believes this setpoint to be the minimum compatible with normal operating conditions. There is no record history of narrow range drywell pressure at Brunswick to be used as a basis, but there is sufficient analytical evidence to support this conclusion.

Due to the relatively low free volume of the Mark I type containment, this setpoint provides a very reliable and sensitive means of detecting and protecting against breaks and leaks in the reactor coolant system.

Containment pressure will exceed this setpoint in less than one second after a design basis LOCA as analyzed in the FSAR. A break size of one square inch would cause 2 psig to be exceeded in less than a minute and a half, assuming an initial pressure of 0 psig. The containment is usually maintained between 0.15 and 1.25 psig during normal operation in order to meet the technical specification limits of -0.5 and 1.75 psig. This "operating band" is required to accommodate normal pressure fluctuations due to heat loads and nitrogen makeup to the inerted containment. Using an FSAR analysis, a loss of all drywell cooling capability during normal full power operation, would cause a 2 psig increase in containment pressure in approximately six minutes.

The Brunswick design is well within the guide lines set forth in the clarification to Position 5, which suggests a maximum of 1 psig differential between maximum expected containment pressure and instrument setpoint. The maximum expected containment pressure during normal operation is 1.25 psig. The pressure instruments are actually calibrated to a setpoint which is below 2 psig by the amount of the instrument error to ensure the technical specification limit of less than or equal to 2 psig is met. The pressure margin, therefore, can actually be expected to be less than .65 psig.

CP&L believes the present pressure setpoint is justified and does not plan on changing the current setpoint.

The inspector verified during normal plant tours, that the containment pressure average readings during normal operation range from approximately .5 to .8 psig.

The inspector had no further questions in this area.

7. Review of Periodic Reports

The inspector reviewed the following Licensee Report.

-- Brunswick Steam Electric Plant, Units Nos. 1 and 2, Monthly Operation Report for April 1981.

The inspector verified that the information reported by the licensee is technically adequate and satisfies applicable reporting requirements established in 10 CFR 50, and Technical Specifications.

The inspector had no further questions in this area. No violations were identified.

8. Onsite Review Committees

The inspectors attended the regular monthly Plant Nuclear Safety Committee (PNSC) Meeting and several special PNSC meetings conducted during the period of May 15 through June 15, 1981.

The inspectors verified the following items:

-- Meetings were conducted in accordance with Technical Specification requirements regarding quorom membership, review process, frequency and personnel qualification;

-- Meeting minutes were reviewed to confirm that decisions/recommendations were reflected and followup of corrective actions were completed.

No violations were identified.

9. Plant Transients

a. On June 1, 1981, while in the shutdown condition, Unit 1 reactor vessel level decreased from 34" to approximately -50", when water was inadvertently discharged from the reactor to the Radwaste neutralizing tanks. Prior to the event, the core was being cooled by circulating vessel water via the RHR system to the fuel pool heat exchangers. Both RHR subsystems were out of service for repairs and cleaning necessitated by oyster growth in the service water system. At approximately 1300 hours, the fuel pool filter was placed in service, thereby, establishing a flow path to Radwaste through the normally closed 3" 1G41-V38 valve. At 1315 hours, channel A, low level circuit tripped. Subsequent action by operating personnel, resulted in locating and isolating the flow path by 1335 hours. Investigation of the incident revealed the following:

   -- Operating personnel responded in a timely and expeditious manner to the dropping level once alerted to the situation.

   -- The RHR isolation valves 1E11-F008 and 1E11-F009, which would have isolated the RHR suction line, received no isolation signal because the associated instruments were out of service. Technical Specifications do not require these in condition 4 and 5.

   -- Technical Specifications do not require any low or low low vessel level instrumentation to be operable in modes 4 and 5. Thus, Technical Specifications require no warning to operators prior to initiation of Core Spray and LPCI.

   -- A valve lineup on May 22, 1981, indicated that 1G41-V38 was closed. No cause for the valve misposition could be determined.

The licensee is currently evaluating which, if any, isolation actuation instruments or level instruments should be operational during conditions 4 and 5. The licensee will submit proposed Technical Specifications change, if any, by August 7, 1981. This is an Inspector Follow-up Item (325/81-12-04).

b. The MSIV 1B21-F022-C, which caused Unit 1 shutdown on March 29, 1981, (refer to Inspection Report 50-325/81-08), has been inspected and repaired. The round pin which attaches the stem disk to the stem, had failed due to fatigue. The stem disk and main disk have been double pinned to prevent recurrence. The vendor, Rockwell-Edwards, concurred with this method in April 1979. However, neither the vendor nor General Electric has been able to determine the mechanism by which sufficient torque would be supplied to unscrew the stem disk and break the pin. During installation, the stem disk is tightened to 1,050 ft.-lbs. prior to pinning. A history of other such problems of the Y-Globe MSIV's at Brunswick is provided below.

Jan. 1976 - Main disk of 2B21-F022-D, separated from stem. Probable cause is installation error. There is no evidence that the pin had been inserted into the stem.

Jan. 1979 - Stem disk of 2B21-F022-A, separated from stem. Probable cause is use of a square pin in a round hole. The corners experience high stress, thereby causing cracking of pin.

Unit 2 outage 1979 - Valves 2B21-F022-D and 2B21-F028-D, were repaired because of local leak rate test results. The round pins in the stem disk were found to be deformed.

Jan. 1981 - Main disk of 2B21-F028-C, separated from stem. Probable cause is installation error. No evidence that a pin was ever inserted, e.g., hole not deformed and no sign of a tack weld.

Examination of records indicate that three valves on Unit 2 may have square pins.

All valves which have been reworked since the 1979 Unit 2 outage, have been double pinned. The licensee's future plan is to continue to double pin all valves as they are removed for any type of repair.

The inspector has no further questions at this time.

c. While conducting a startup on Unit 2 with the reactor at approximately 15% power at 2100 hours on June 15, 1981, the package boiler was supplying steam at 40 lbs. for the Nitrogen vaporizer. The auxiliary operator noticed erratic level and dropping pressure and flames emitting from the stack. The boiler was shutdown and declared inoperable at approximately 2330 hours. This package boiler is the only source of auxiliary steam available for operation of the Nitrogen inerting steam vaporizer. This rendered the normal means for inerting of the primary containment inoperable. Oxygen concentration in the primary containment was approximately 11% and loss of the ability to reduce the oxygen concentration by inerting invoked Technical Specification 3.6.6.3, "Limiting Condition for Operation",that requires oxygen concentration to be less than 4% by volume within 24 hours after exceeding 15% thermal power. Reactor power was reduced by Xenon buildup to approximately 13.5% at approximately 0130 hours and maintained below 15% while initially investigating the cause and possible repair of the package boiler.

Subsequent investigation revealed extensive tube damage to the boiler that could not be repaired within the 24 hour limit as specified in Technical Specifications. The licensee is attempting to obtain from NRR temporary relief from this requirement to allow power operation until either a replacement boiler can be obtained or the affected boiler repaired.

This is an Inspector Follow-up Item pending resolution. (325/81-12-05)

10. Review of Plant Operations

a. The inspector reviewed plant operations through direct inspections and observations throughout the reporting period. The following areas were inspected.

(1) Control Room
(2) Service Building
(3) Reactor Building
(4) Diesel Generator Rooms
(5) Control Points
(6) Site Perimeter

b. The following determinations were made:

-- Monitoring instrumentation: The inspector verified that selected instruments were functional and demonstrated parameters within Technical Specification limits.

-- Valve positions. The inspector verified that selected valves were in the position or condition required by Technical Specifications for the applicable plant mode. This verification included control board indication and field observation of valve position (Safeguards Systems).

-- Plant housekeeping conditions. See paragraph 4.

- -- Fluid leaks. No fluid leaks were observed which had not been identified by station personnel and for which corrective action had not been initiated, as necessary. The licensee signed a contract during May with Underwater Construction Co. to repair the Unit 1 and Unit 2 Spent Fuel Pool leaks. The licensee expects preliminary work on Unit 2 to begin in late June. Underwater Construction Co. has successfully located and repaired leaks at other facilities. This item remains open 324/79-07-03.

- -- Control room annunciators. Selected lit annunciators were discussed with control room operators to verify that the reasons for them were understood and corrective action, if required, was being taken.

- -- By frequent observation throughout the inspection period, the inspector verified that control room manning requirements of 10 CFR 50.54(k) and the Technical Specifications were being met. In addition, the inspector observed shift turnovers to verify the continuity of system status was maintained. The inspector periodically questioned shift personnel relative to their awareness of plant conditions.

No Violations were identified in this area.