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

Report Nos.: 50-325/86-17 and 50-324/86-18

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket Nos.: 50-325 and 50-324 License Nos.: DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: July 1-31, 1986

Inspectors: J. S. Mellen 9/10/86
For W. H. Ruland Date Signed

J. S. Mellen 9/10/86
for L. W. Garner Date Signed

Approved by: P. E. Fredrickson 9/12/86
P. E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspector safety inspection examined the areas of maintenance engineered safety features observation, surveillance observation, operational safety verification, onsite follow-up of events, survey of licensee's response to selected safety issues, ESF system walkdown, and TIP tube reversal.

Results: Two violations were identified: failure to follow procedures concerning smoking and failure to follow procedure concerning rigging scaffolding to a snubber extension.

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REPORT DETAILS

1. Licensee Employees Contacted

   P. Howe, Vice President - Brunswick Nuclear Project
   C. Dietz, General Manager - Brunswick Nuclear Project
   T. Wyllie, Manager - Engineering and Construction
   J. Holder, Manager - Outages
   E. Bishop, Manager - Operations
   L. Jones, Director - Quality Assurance (QA)/Quality Control (QC)
   R. Helme, Director - Onsite Nuclear Safety - BSEP
   J. Chase, Assistant to General Manager
   J. O'Sullivan, Manager - Maintenance
   G. Cheatham, Manager - Environmental & Radiation Control
   E. Enzor, Director - Regulatory Compliance
   B. Hinkley, Manager - Technical Support
   R. Groover, Manager - Project Construction
   A. Hegler, Superintendent - Operations
   W. Hogle, Engineering Supervisor
   B. Wilson, Engineering Supervisor
   R. Creech, I&C/Electrical Maintenance Supervisor (Unit 2)
   R. Warden, I&C/Electrical Maintenance Supervisor (Unit 1)
   W. Dorman, Supervisor - Quality Assurance (QA)
   W. Hatcher, Supervisor - Security
   R. Kitchen, Mechanical Maintenance Supervisor (Unit 2)
   C. Treubel, Mechanical Maintenance Supervisor (Unit 1)
   R. Poulk, Senior NRC Regulatory Specialist
   D. Novotny, Senior Regulatory Specialist
   W. Murray, Senior Engineer - Nuclear Licensing Unit
   W. Ziegler, Principal Engineer - Corporate Nuclear Fuels Section, Operations Support

   Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, office personnel, and security force members.

2. Exit Interview (30703)

   The inspection scope and findings were summarized on August 4, 1986, with the vice-president and general manager. The two violations, failure to follow procedure regarding smoking and failure to follow procedure regarding rigging scaffolding to a snubber attachment (paragraph 6), were discussed in detail. Also discussed was management tours of the vital areas (paragraph 6). One Unresolved Item*, TIP Tubing Reversal (paragraph 10), was discussed with the general manager during a special meeting on July 25, 1986. The

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*Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations.

licensee acknowledged the findings without exception. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during the inspection.

3. Followup on Previous Enforcement Matters (92702)

Not inspected.

4. Maintenance Observation (62703)

The inspectors observed maintenance activities and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service. Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance.

The inspectors observed/reviewed portions of the following maintenance activities:

86-BDAG1	2-G31-F001 Failed to Close on Group 2 Signal.
86-BDGB1	Reactor Manual Control System Inadvertent Rod Movements.
86-BFFC1	Nuclear Service Water Low Pressure Annunciator Transmitter Calibration.
86-BFQA1	Work on G16-F003 Valve.
MI-03-03A	General Pressure/Vacuum Switches Instrument Calibration.
MI-03-4U12	Texas Instrument TIGRAPH 200 Recorder Calibration.
MI-03-38A5	General Electric Power Supply Type 570-06 Calibration.

No violations or deviations were identified.

5. Survei .ance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications. Through observation and record review, the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors independently verified selected test results and proper return to service of equipment.

The inspectors witnessed/reviewed portions of the following test activities:

E&RC-0358	Weekly Check of the Area Radiation Monitors High and Low Setpoint Alarms.
E&RC-1221	Sampling and Analysis Procedure for Routine Steam Jet Air Ejector Off-Gas Analysis.
E&RC-1222	Operation of Gas Chromatograph.
E&RC-2016	Sampling and Analysis of Drywell Purges.
1 MST-PCIS25M	PCIS High Main Steam Line Flow Trip Unit Channel A1 Calibration.
OI-03.1	Periodic Testing and Control Operator Daily Surveillance Report - Unit 1.
OI-03.2	Periodic Testing and Control Operator Daily Surveillance Report - Unit 2.
PT-01.11	Core Performance Parameter Check.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

The inspectors verified conformance with regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the Technical Specifications were met. Control room, shift supervisor, clearance and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specifications Limiting Conditions for Operations. Direct observations were conducted of control room panels, instrumentation and recorder traces important to safety to verify operability and that parameters were within Technical Specification limits. The inspectors reviewed shift turnover sheets to verify that continuity of system status was maintained. The inspectors verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature (ESF) train was verified by insuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker, including control room fuses, were aligned for components that must activate upon initiation signal; removal of power from those ESF motor-operated valves, so identified by Technical Specifications, was completed; there was no leakage of major components; there was proper lubrication and cooling water available; and a condition did not exist which might prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

The inspectors verified that the licensee's health physics policies/ procedures were followed. This included a review of area surveys, radiation work permits, posting, and instrument calibration.

The inspectors verified that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the protected area (PA); vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; and effective compensatory measures were employed when required.

The inspectors also observed plant housekeeping controls, verified position of certain containment isolation valves, checked a clearance, and verified the operability of onsite and offsite emergency power sources.

a. Open Control Room Airlock Doors

On July 8, 1986, at about 7:15 a.m., the inspector observed that both doors of an airlock leading into the back of the control room were open. The inner door had been removed for modification and the outer door had been wired opened. In accordance with the security plan, a security guard was posted at the vital entrance, the inner door. The passageway leads to a metal office building which had been added to the radwaste roof after original construction. Onshift responsible personnel were unaware of the condition and had not authorized opening of the outer door. At the time work was authorized, verbal instructions had been issued to keep the outer door closed. The outer door is clearly marked as "Fire Door/Keep Closed." However, at the time, the outer door was posted as being an inoperable fire door and was being monitored by a roving fire watch.

Final Safety Analysis Report, amendment No. 4, dated June 2, 1986, describes the leak tightness and toxic gas protections of the control room. Section 6.4.2.4, Interaction with Other Zones and Pressure-Containing Equipment, states:

> The following provisions were taken into consideration in the Control Room Area Ventilation System design to assure that there are no toxic or radioactive gases and other hazardous material that would transfer into the Control Room:
>
> (a) The Control Room envelope is maintained at static pressures slightly higher than atmospheric to prevent infiltration from the outside.
>
> (b) Doors and other openings into the Control Room are conspicuously marked to assure that they will normally remain closed. This administrative control will assure that the Control Room normally remains closed. The doors are equipped with reclosers.

Section 6.4.4.2 states:

> Infusion of chlorine contaminated air will be inhibited by:
>
> 1) Quick-acting dampers having a maximum travel time of five seconds or less. Total isolation time (time between 5 ppm chlorine signal at the control room chlorine detector and completed damper travel) requirement is less than or equal to 10 seconds.
>
> 2) Tightly fitting and weather-stripped doors, and
>
> 3) By having all cable conduits to the Control Room potted or sealed.

In addition, Technical Specification 3.7.2 requires two control room emergency filtration systems be operable or the unit must be in at least hot shutdown within 12 hours and in cold shutdown within the next 24 hours. One of the conditions of operability is the successful completion of surveillance requirement 4.7.2.d.4, which requires every 18 months a verification that the system maintains the control room at a positive pressure relative to the outside atmosphere during system operation.

The licensee is investigating the event. The licensee reports that the outer door was opened between 6 and 7 p.m. on the preceding day (July 7, 1986), was closed about midnight and then re-opened some time prior to the inspector's discovery. Hence, it appears that the 12 hours to be in hot shutdown was not exceeded. Also, after the fact, the licensee performed a test with both the doors open and showed that with the emergency filtration system operating, smoke would blow out the passageway away from the control room. The tank car siding chlorine monitors, not assumed operable for the FSAR analysis, were also operable during this time.

The licensee interviewed personnel involved. Because of the heat and poor ventilation in the area, an individual apparently attempted to find out why the outer door could not be opened. In discussions with a non-licensed operations department staff member, the individual thought that he had gotten permission to leave the door open. However, the operations person, after seeing that the fire door was already under fire watch, apparently indicated that he saw no reason why it should not be opened. The operations person believed that this was only for a short duration to allow some air flow and did not intend to give the impression that it could remain open. This miscommunications led to the first instance of wiring the door open. The circumstances around the second instance is still being reviewed.

During the review, the licensee determined that the on-duty senior auxiliary operator, a licensed individual, and a shift technical advisor made one or more entrances or exits through the passageway while both doors were open. Neither apparently recognized that the condition could adversely impact the control room habitability as described in Technical Specifications and the FSAR. The inspectors have concluded that no violations ;of the control room boundary occurred. The guard who was posted on the door, could have shut the door in the event of an accidental chlorine release maintaining the boundary. The inspector plans to review the licensee's determinations concerning the breakdown in work controls and actions to prevent recurrence when the experience report is completed. This is an Inspector Followup Item, Review of Unauthorized Control Room Pressure Boundary Extensions (325/86-17-03 and 324/86-18-03).

b. Scaffolding Attached to Seismic Support

On July 11, 1986, the inspector observed scaffolding attached to the Unit 1 Reactor Core Isolation Cooling (RCIC) System discharge line seismic support. A 4 by 4 was resting on and wired to the snubber, E51-41SS89, attachment rod and paddle assembly. The scaffolding had been erected on July 8, 1986, by a craft worker of the mechanical construction group. Procedure WP-18, Temporary Construction Loads, states that "Rigging from pipe hanger struts, spring cans, snubbers or snubber parts shall not be allowed." The scaffolding had been rigged on the snubber attachment, a snubber part, and thus was prohibited by WP-18. 10 CFR 50, Appendix B, Criterion V, requires activities affecting quality shall be accomplished by procedures. Failure to follow WP-18 in the rigging of scaffolding is a violation: Rigging Scaffolding to RCIC Snubber Attachment (325/86-17-01).

c. CAC-V10 Open During Walkdown

On July 17, 1986, while performing a walkdown of the Unit 2 main control bcard, the inspector found CAC-V10, Outboard Drywell Purge Exhaust Valve, open. In accordance with procedure OP-24, Containment Atmosphere Control System, Revision 67, the valve is normally closed per valve check list page 107, and is specified to be closed after primary containment inerting per step 7.1.B.9. The on-duty operator indicated that it had been closed during turnover, about 30 minutes earlier. He cycled the valve and left it in the closed position. He further commented that the valve had been slow to open during his last use of the valve. However, no difficulty had been observed in closing the valve. CAC-V10 receives a close signal during a Group 6 isolation. CAC-V9, Drywell purge exhaust isolation valve, was closed when CAC-V10 was found open, maintaining the containment. The licensee initiated work request 86-BEAH1. Further review revealed that this condition had been reported earlier on work request 86-BAEF1, dated June 18, 1986. Apparently, an operator had given the valve an open signal and the valve had stayed closed. Then, at some later time, the valve opened. The inspector verified that the valve logic would allow the valve to perform in this fashion. Instructions have now been issued to operators to log the opening of the valve and any problems encountered. The inspector has no further questions at this time.

d. Smoking In Diesel Generator Building

The inspector found eight smoked cigarette butts in two ventilation ducts in the diesel generator building. The ventilation ducts connect the emergency switch gear rooms with the diesel generator fan room. The rooms are separated by a concrete wall with the exception of the ducts. Both rooms are frequently patrolled by Technical Specification required fire watches. The inspector did not find anyone smoking cigarettes in the diesel building. However, the inspector believes that evidence of smoking is sufficient reason to warrant further management attention.

Fire Protection Procedure FPP-014, Rev. 2, Control of Combustible, Transient Fire Loads and Ignition Sources, attachment 3, lists the Diesel Generator Building as a no smoking area. The cigarette butts found in the ventilation duct indicate that smoking had occurred in the building. This failure to follow procedure FPP-014 is a violation: Cigarette Smoking in the Diesel Generator Building (375/86-17-02 and 324/86-18-02).

e. Management Entry Into Vital Areas

The inspector reviewed security access logs to verify that plant management toured the vital areas on a regular basis. The inspector reviewed the personnel transactions of management as recorded by the Brunswick Security System from June 26 to July 28, and also on July 29, 1986. The vice-president and several managers, and most of the principal managers had made several tours during the above period. A few managers had not conducted tours of the plant during this period. The operations superintendent, whose office is in the control room, had not entered either the reactor building, the service water building, or the diesel generator building during the period. However, the operations superintendent had been off-site about ten days during the above period. The inspector discussed the issue with senior plant management. Management visits to the plant will continue to be monitored by the inspectors.

Two violations and no deviations were identified.

7. Onsite Follow-up of Events (93702)

On July 11, 1986, at 3:03 a.m. Unit 2 was manually scrammed from 17% of full power while conducting a normal reactor shutdown to repair a reactor water cleanup (RWCU) valve. The licensee decided to scram the unit earlier than anticipated because of problems with the reactor manual control system (RMCS). After the scram, the licensee found that the inboard drywell floor drain primary containment isolation valve, G16-F003, had failed to close on a group 2 isolation signal and Source Range Monitor (SRM) C had failed downscale. Excluding these items, all systems responded as expected and the condensate/feedwater systems and main condenser were used for level and pressure control.

Unit 2 was being shutdown to repair the inboard RWCU suction primary containment isolation valve, G31-F001. During surveillance testing, the valve had been observed to bind and trip its breaker on 300% overload. In accordance with Technical Specification 3.6.3.a, the outboard isolation valve was closed, thereby removing RWCU from service. The valve was found to have the actuator bearing house cover cracked with some internal damage to the actuator. The licensee believes the valve may have had a hairline crack in the cover which had not been detected when the valve was repaired during the last outage. The valve had been damaged when it was actuated with the torque switch installed backwards during a post modification test. The licensee inspected the valve disc and seat for damage. None was found. The actuator was repaired and the valve successfully timed and leak checked.

The RMCS malfunction involved the random insertion or withdrawal of a control rod one notch when a rod was selected prior to the operator turning the rod control switch. This was attributed to a loose wire in the RMCS which would cause the RMCS electronic timer to reset after a rod movement was complete and the rod deselected but before the subsequent rod is selected. When a different rod is selected, it can move one notch on its own prior to a command from the operator. The wire was properly secured. The investigation revealed that this phenomenon can also occur if an operator attempts to select a rod while the electronic timer is running. In this case, the operator's action sets up a "relay race" between final rod movement and deselection and selection of the next rod while the timer is running; e.g., if a rod can be selected (rod movement complete, deselection of a rod is complete and the timer is still running), the timer will reset and the newly selected rod will move one notch. The interval during which this can occur is from final rod movement (settle function complete) to the end of the timer sequence, 0.5 seconds. Administrative controls now instruct the operators to verify the timer has stopped prior to selecting the next rod. The licensee is evaluating a modification to prevent the "relay race". The problem with the RMCS did not effect the Rod Sequence Control System (RSCS), that is, at no time was a rod pattern outside the notch constraint pattern when RSCS was controlling.

G16-F003, which had failed to close on the group 2 isolation signal and from the control board manual switch after the scram, functioned correctly during trouble shooting. The licensee suspects that some blockage in the air solenoid may have caused the malfunction and the blockage subsequently cleared. The licensee did not disassemble the solenoid because no rebuild kit was found in stock. The licensee instituted a program to weekly cycle this valve and three similar ones until the affected solenoid is rebuilt and examination of the solenoid internals can be performed. On July 31, 1986, while performing the surveillance, G16-F003 would not shut. The licensee closed the other isolation valve per Technical Specification 3.6.3.a. Instrument and control technicians determined that the solenoid was sticking. Discussions between maintenance and engineering revealed that a rebuild kit was available and had been all along. The solenoid was subsequently repaired and returned to service. Apparently maintenance planners had attempted to locate parts for the old style solenoid which had been removed during the last outage. The inspector plans to review the licensee's experience report concerning failure determination and part mixup when it is issued.

No violations or deviations were found.

8. Survey of Licensee's Response to Selected Safety Issues (TI 2515/77)

The subject Temporary Instruction (TI) involved surveying the actions that the licensee is taking to address two safety issues: reliability of the High Pressure Coolant Injection/Reactor Core Isolation Cooling (HPCI/RCIC) Systems and biofouling of cooling water heat exchangers.

Actions taken through the end of this report period associated with HPCI/RCIC reliability include incorporation of information from vendors, General Electric and Institute of Nuclear Power Operations (INPO), as applicable, into their preventive maintenance, calibration and testing programs. In addition, the licensee established in early 1986 an inter-disciplinary task force to seek additional improvements to increase systems reliability. The areas and goals being studied include: adequacy and frequency of test program, development of methodologies for validating a reliability monitoring program and establishment of an effective reliability monitoring and predictive maintenance program. Completion is expected in 1987. The following NUREG-0737 items regarding HPCI and RCIC have been closed: II.K.3.13, II.K.3.15, II.K.3.22 and II.K.3.24.

The only systems considered susceptible to biofouling are those involving water drawn from the Cape Fear River and marshes. Systems such as the fire protection system using the county water system or deep wells are not considered susceptible to biofouling. An event involving significant degradation of the Residual Heat Removal (RHR) heat exchangers (Hx) was described in Information Notice (IEN) No. 81-21, Potential Loss of Direct Access to Ultimate Heat Sink. The event was attributed to failure to maintain the chlorination system operational during periods of anticipated marine organism growth. Since that time, the chlorination system has been upgraded and chlorination is provided continuously. Since 1982, non-availability of the chlorination system has been limited to less than two weeks. Success of the program has been verified during refueling outages in which inspections of heat exchangers and associated piping has shown little or no evidence of biofouling. The licensee has established procedures and trained operators for coping with significant heat exchanger performance degradation if it should occur. The licensee periodically monitors the RHR Hx baffle plate differential pressure to ensure that biofouling would be detected in time to prevent recurrence of the IEN 81-21 event.

The inspector concluded that the licensee's actions taken in response to these safety issues as well as ongoing actions demonstrate a positive attitude and sensitivity to the importance of these items.

No violations or deviations were identified.

9. Engineered Safety Features System Walkdown (71710)

The inspector performed a complete walkdown of the accessible portions of the Unit 1 and 2 Core Spray System to verify system operability. The inspector verified that: hangers and supports were functional, housekeeping was adequate, valves and pumps were properly maintained, component labeling was correct, instrumentation was properly installed and functioning, power was available to motor-operated valves and that valves were in the correct position, and that the room coolers were operable.

The inspector verified that all system instrumentation was listed on either the periodic test scheduling designator report (for non Technical Specification instruments) or calibrated using a PT or MST (for Technical Specification instruments). All system instrumentation required for system operability was verified installed and calibrated.

The inspector verified that the system checklists in OP-18, Core Spray (CS) System Operating Procedure, Revision 6 for Unit 1 and Revision 24 for Unit 2, contained the major system valves as indicated by the Core Spray piping and instrumentation drawings (P&ID), [D-25024, Sh. 1 (Rev. 19), D-25024, Sh. 2 (Rev. 17), D-2524, Sh. 1 (Rev. 20), D-2524, Sh. 2 (Rev. 19)].

The inspector found two drawing discrepancies on the CS P&ID's. The isolation valves for the CS leak detection instrumentation (V87, V88) were shown as open on the Unit 1 P&ID but shown as locked open on the Unit 2 P&ID. The Unit 1 P&ID did not show that pressure switches PS-N008A & B, and PS-N009A & B supplied the ADS permissive logic. The licensee will correct the drawings.

The licensee has removed the Unit 1 Division I & II core spray suction relief valves, F032A & B. The licensee has removed the valves because they leaked by and replacements were not readily available. EER 85-256 allows continued operation of the system with 1-E21-F032A removed and the suction valves caution tagged to prevent operation with both the torus and condensate storage tank suction valves shut. A similar EER was issued for 1-E21-F032B. The relief valve's setpoint was 125 plus or minus 10 psig to protect the suction piping in case both suction lines are isolated and the discharge line valves leaked by. The relief valve lines are now capped with a 150 psig flange that has been operationally leak tested. The EER expires September 15, 1986. The inspector has no further questions about the suction relief valves at this time. The inspector verified that the readings of the four core spray sparger high differential pressure switches were consistent with the system description.

The inspector compared the readings of the four core spray sparker high differential pressure switches. They read as follows:

1-E21-N004A:	110" with plus or minus 3" swings
1-E21-N004B:	100"
2-E21-N004A:	93"
2-E21-N004B:	156"

The inspector found the 3/4" instrument line to 2-E21-PSH-N007A not clamped to two unistruts. The licensee had previously identified a similar condition during the blanket walkdown of Unit 1. The blanket walkdown of Unit 2, scheduled to start during the current operating cycle, most likely would have identified the missing unistrut clamps. The inspector also found that the Service Water (SW) valve solenoid valves to the CS room cooler for both Units were not mounted properly. The licensee reported to the inspector the solenoid valves de-energize when core spray initiates, opening the SW supply to the room coolers. The screws that fastened the solenoid valve to a mounting bracket on the main valve body were missing on three of four coolers and only one screw was in place for the remaining solenoid. The licensee reported that a safety concern did not exist since, on loss of air, the SW valves would open, supplying water to the room coolers.

The inspector found scaffolding erected near the Unit 1 CS F004B and F005B valves and the Unit 2 F004A and F005B valves. The scaffolding was constructed of fire-retardant wood. However, no work was being done near those valves and the Unit 1 outage had been completed 200 days ago. The licensee issued work requests to remove the scaffolding.

No violations or deviations were identified.

10. TIP Tubing Reversal

At about 4:00 p.m. on July 22, 1984, with Unit 2 at 100% power, the licensee discovered that Traversing Incore Probe (TIP) tubes might have been reversed on Unit 2. The licensee reduced power, confirmed the swap through control rod movements and requested the corporate Incore Analysis Unit to calculate the effect on thermal limits. Further testing was performed to verify that no other TIP tubes were reversed. A modification to the process computer program was made to compensate for the swap. Unit 2 was returned to 100% power on July 25, 1986.

The licensee discovered the TIP tube swap during a routine review of TIP traces by the Nuclear Engineering Staff. The TIPs are used to calibrate the Local Power Range Monitors (LPRM) which are in turn used by the process computer to calculate margins to thermal limits. There are four TIP machines, each with its associated detector. Each machine's detector can be selected to traverse eight or nine LPRM strings. Position ten is the common channel such that each machine can traverse the same LPRM location (28-29) to cross-calibrate the TIP machines. The TIP output is also sent to an X-Y plotter to draw a trace on graph paper. During a review of the A-10, B-10, C-10 and D-10 traces (common location) taken during the OD-1 calibration, the licensee noted that the 10 trace did not match the A-10, C-10 and D-10 trace low in the core. The center rod, near the common channel, was inserted to position 36. Further review showed that the B-8 flux shape did resemble A-10, C-10 and D-10.

Reactor power was reduced to 95% within one hour for added assurance that no Technical Specification thermal limits were being exceeded. The margin to critical power ratio was approximately 5% before the power reduction. Thus, after power was reduced, about a 10% margin to thermal limits was available to compensate for any errors in the LPRM calibrations. The licensee used control rod motions with TIP traverses to verify that B-8 and B-10 were swapped. Power was reduced to about 75% power. A TIP trace was taken before and after a rod was moved near a TIP locations.

The Incore Analysis Unit of the corporate Nuclear Fuel Section conducted off-line analysis of cycle 7 data to verify that no thermal limits had been exceeded. The BACKUP code was used. Since B-8 and B-10 were swapped, the normalization of the TIP machines and their associated LPRMs were affected. Since actual local power B-8 was predominantly lower than actual B-10 local power, the swap forced the normalization process to raise the associated readings for the TIP B machine calibrated LPRMs. This resulted in conservative thermal limit calculations for fuel near TIP B calibrated LPRMs but non-conservative thermal limit calculations for fuel near TIP A, C, and D calibrated LPRMs. However, since the cross-calibration process is a normalization process, the magnitude of the conservative error in the single B machine is averaged over machines A, C and D, leading to a smaller non-conservative error. The licensee reviewed all cycle 7 data and found that during high power when thermal limits could be approached, the most limiting location for thermal limits were being monitored by a TIP B calibrated LPRM. Since TIP B gave conservative readings, no thermal limits had been exceeded during cycle 7.

The inspectors reviewed selected licensee P1 printouts and core thermal limit data (PT 1.11) to verify that the licensee's claims regarding power history were supported by the data.

On July 23, 1986, Special Procedure SP-86-041 was written and performed to verify that no other TIP tubes were swapped. No additional problems were found.

On July 24, 1986, the licensee modified the process computer program to compensate for the B-8, B-10 swap. The changes were made to the Digital Fast Scan program and to the TIP driver software to swap B-8 and B-10 locations. The licensee verified that the computer program modifications are functional.

On the afternoon of July 25, 1986, the licensee returned Unit 2 to 100% power. The licensee had, at that time, presented their cycle 7 thermal limit review information to the resident inspectors. The licensee had previously agreed in a letter dated July 23, 1986, not to exceed 95% without Region II concurrence. Based upon information given to the residents, Region II concurred in Unit 2 return to 100% power. However, the licensee has agreed to review cycle 6 data for compliance with thermal limits and to further investigate how and when the TIP was reversed. The NRC will review the licensee's additional information when available for possible enforcement actions. Pending completion of the licensee's review, this is an Unresolved Item: TIP Tube Reversal (324/86-18-04).