UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

January 25, 2012

Mr. Michael Annacone
Vice President
Carolina Power and Light Company
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, North Carolina 28461

SUBJECT: BRUNSWICK NUCLEAR PLANT – NRC SPECIAL INSPECTION REPORT 05000324/2011013

Dear Mr. Annacone:

On November 30, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed a reactive inspection pursuant to Inspection Procedure 93812, "Special Inspection," at your Brunswick Nuclear Plant Unit 2. The enclosed inspection report documents the inspection results, which were discussed on December 15, 2011, with yourself and other members of your staff.

The special inspection was commenced on November 21, 2011, in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Manual 0309, "Reactive Inspection Decision Basis for Reactors," based on the initial risk and deterministic criteria evaluation made by the NRC on November 18, 2011.

The special inspection reviewed the circumstances surrounding the integrity of the Brunswick Unit 2 nuclear plant reactor coolant system pressure boundary during start-up which occurred on November 16, 2011, and examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publically Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Randall A. Musser, Chief
Reactor Projects Branch 4
Division of Reactor Projects

Docket No: 50-324
License No: DPR-62

Enclosure: Inspection Report 05000324/2011013
w/Attachments

Attachments: 1. Supplemental Information
2. Brunswick Special Inspection Charter

cc w/encl: (See page 3)

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Letter to Michael J. Annacone from Randall A. Musser dated January 25, 2012

SUBJECT: BRUNSWICK NUCLEAR PLANT – NRC SPECIAL INSPECTION REPORT 05000324/2011013

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-324
License Nos.:	DPR-62
Report No:	05000324/2011013
Licensee:	Carolina Power and Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Unit 2
Location:	8470 River Road, SE Southport, NC 28461
Dates:	November 21 to November 30, 2011
Inspectors:	R. Taylor, Senior Project Inspector, Team Lead P. O'Bryan, Senior Resident Inspector E. Stamm, Project Engineer
Approved by:	Randall A. Musser, Chief Reactor Projects Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000324/2011-013; 11/21/2011 – 11/30/2011; Brunswick Steam Electric Plant, Unit 2; Special Inspection

This Special Inspection was conducted by a Senior Project Inspector, Senior Resident Inspector, and Project Engineer from the Region II office using Inspection Procedure 93812 to assess the circumstances concerning the integrity of the nuclear plant reactor coolant system pressure boundary at Brunswick Unit 2.

A. NRC-Identified and Self-Revealing Findings

None.

B. Licensee Identified Violations

None.

REPORT DETAILS

Event Description:

On November 16, 2011, at 2:12 a.m., operators at Brunswick Nuclear Plant Unit 2 calculated a drywell floor drain leak rate of 5.88 gpm following several hours of gradually rising floor drain leakage during a plant startup. Technical Specification 3.4.4 A was entered requiring floor drain leakage to be restored below 5 gpm within 8 hours. At 2:53 a.m., the calculated leak rate was 10.11 gpm. At 3:01 a.m., a Notice of Unusual Event (NOUE) was declared for unidentified leakage exceeding 10 gpm. At 3:09 a.m., the licensee initiated a manual reactor scram from approximately 7 percent power. Following the scram, reactor pressure was decreased and the unidentified leak rate dropped below 10 gpm within 1 hour and was less than 5 gpm within 2 hours. The leak rate at 6:14 a.m. was 3.82 gpm with reactor pressure at 228 psig.

The NOUE was exited at 8:15 a.m. on November 16, 2011, when leakage could be maintained below 10 gpm due to decreasing pressure. The unit was cooled down and reached cold shutdown at 2:38 p.m. on November 16, 2011.

On November 17, 2011, the licensee determined that the reactor head flange leakage was due to inadequate reactor vessel head stud tensioning.

Special Inspection Team Charter

Based on the criteria specified in MD 8.3, ”NRC Incident Investigation Program,” a Special Inspection was initiated in accordance with Inspection Procedure 93812, “Special Inspection.” The objectives of the inspection, described in the charter, are listed below and are addressed in the identified sections:

(1) Develop a timeline associated with this event. (Section 4OA3.1)

(2) Assess the ability of the reactor vessel to meet its design basis functions with the as found condition. (Section 4OA3.2)

(3) Assess the tensioning method for the head studs, the training provided to maintenance, and quality control inspectors for this evolution. (Section 4OA3.3)

(4) Assess the data and procedures from the last Unit 1 refueling outage to determine if the head tensioning process was completed correctly. (Section 4OA3.4)

(5) Assess the completed outage procedures for head tensioning to determine if all of the verifications and quality control hold points were completed prior to mode changes. (Section 4OA3.5)

(6) Assess the condition of the reactor vessel head bolts, the reactor vessel head flange and the o-rings and seating surfaces to determine if damage occurred due to the leakage. (Section 4OA3.6)

(7) Assess the test program for verifying reactor coolant system integrity after head installation to determine if the licensee was in compliance with ASME testing requirements. (Section 4OA3.7)

(8) Assess operator performance during the event to determine if there were earlier indications of RCS leakage prior to reaching mode 2 and seven percent. (Section 40A3.8)

(9) Assess the licensee's activities related to the problem investigation performed to date (e.g., root cause analysis, extent of condition, additional equipment failure mechanisms, etc.), including any safety culture aspects. (Section 40A3.9)

(10) Assess the licensee's actions for previous significant outage events to determine if lessons learned could have prevented the issue. (Section 40A3.10)

4. OTHER ACTIVITIES

4OA3 Event Follow-up - Special Inspection (93812)

.1 Develop a timeline associated with this event.

On November 16, 2011, with Unit 2 operating in mode 2 at 7 percent power, operators responded to an increase in unidentified leakage inside of primary containment (drywell) by inserting a reactor scram and declaring an Unusual Event. Events occurred as indicated by the following timeline.

11/4/11 9:07 p.m. The Unit 2 reactor was shut down for a mid-cycle maintenance outage. The licensee shutdown to address indications of a reactor fuel leak, which requires that the reactor be disassembled and the fuel bundles individually inspected for leakage.

11/6/11 7:27 a.m.: Unit 2 entered mode 5 and reactor disassembly commenced.

11/12/11 5:00 p.m.: The Unit 2 reactor head was set during reactor reassembly after completion of the fuel inspections and bundle replacements.

11/13/11 3:13 a.m.: Initial reactor head stud measurements were completed in preparation for reactor head stud tensioning. Tensioning of the studs began. During the evolution, over the next three hours, operators of the stud tensioning pump failed to apply proper pressure to the stud tensioning devices due to a lack of understanding of the pump pressure indication. Approximately 1,300 psi was applied to the tensioning devices vice the required 13,000 psi.

11/13/11 6:39 a.m.: The reactor head stud tensioning procedure was completed, including final stud elongation measurements. During review of the elongation data, maintenance personnel mistakenly interpreted the readings to conclude that sufficient stud elongation was obtained. However, the data actually showed that the studs were not sufficiently elongated.

<u>11/13/11 7:35 a.m.</u>: The licensee declared the Unit 2 reactor to be in Mode 4.

<u>11/15/11 2:00 a.m.</u>: The Unit 2 reactor Mode switch was placed in STARTUP/HOT STANDBY and the licensee declared the reactor to be in mode 2.

<u>11/15/11 2:58 a.m.</u>: Unit 2 reactor control rod withdrawal commenced.

<u>11/15/11, approximately 8:00 p.m.</u>: Based on the frequency and amount of the drywell sump pumping, the operating crew determined that the drywell floor drain (DWFD) leakage was abnormal. The calculated 4-hour average leak rate from 4:00 p.m. to 8:00 p.m. was 0.1 gpm, indicating that significant leakage started late in the 4 hour period between 4:00 p.m. and 8:00 p.m. The Outage Control Center (OCC) was notified of the abnormal leakage. The operating crew attributed the increased DWFD leakage to the 2-B32-F031B valve, which was noted to have packing leakage during the previous startup. The OCC prepared to send personnel into the drywell to backseat the valve.

<u>11/16/11 12:00 a.m.</u>: Backseating of 2-B32-F031B was complete. The midnight 4-hour leakage rate was calculated to be 3.99 gpm. Startup activities were paused to determine the effect of backseating 2-B32-F031B and to further investigate the cause of the increased DWFD leakage.

<u>11/16/11 12:54 a.m.</u>: OCC and Operations management started preparations for a second drywell entry to assess the leakage. A chemistry sample of the DWFD sump was also planned to assess the origin of the leak.

<u>11/16/11 2:12 a.m.</u>: DWFD leakage rate was calculated to be 5.88 gpm based on the cycling of the DWFD sump pumps. The crew declared the TS LCO for unidentified leakage inside of the primary containment greater than 5 gpm to be in effect.

<u>11/16/11, approximately 2:30 a.m.</u>: Personnel entered the drywell, noted water dripping from equipment and the drywell walls, and reported to the OCC that the drywell atmosphere was “very humid.”

<u>11/16/11 2:35 a.m.</u>: The 92’ elevation of the drywell (highest elevation) temperature was observed to be 240 degrees F by the operations crew. The normal temperature of the 92’ elevation is approximately 200 degrees F. Operators recognized that this was an indication of a leak in the upper portion of the drywell, and not a leak from the 2-B32-F031B valve. Operators started making preparations to shut down the reactor.

<u>11/16/11 2:53 a.m.</u>: The DWFD leak rate was calculated to be 10.11 gpm based on the cycling of the DWFD sump pumps. The Operations Shift Manager ordered the evacuation of personnel from the drywell.

11/16/11 3:01 a.m.: Operators declared an Unusual Event due to unidentified leakage exceeding 10 gpm.

11/16/11 3:09 a.m.: After a short operations crew brief, the Unit 2 reactor was scrammed, and plant cooldown and depressurization commenced.

11/16/11 3:09 a.m. – 2:38 p.m.: The Unit 2 reactor was cooled down and depressurized. DWFD leakage lowered as reactor pressure was reduced. DWFD leakage was calculated to be 5.27 gpm at 4:30 a.m. and 3.82 gpm at 6:14 a.m..

11/16/11 2:38 p.m.: Unit 2 entered mode 4. The DWFD leakage rate in mode 4 was approximately 0.13 gpm.

11/17/11, approximately 1:00 p.m.: During trouble-shooting activities on the refueling floor, maintenance personnel were able to turn several of the reactor head retaining nuts by hand, indicating improper reactor head stud tensioning. The licensee declared the Unit 2 reactor to be in mode 5.

.2 Assess the ability of the reactor vessel to meet its design basis functions with the as-found condition.

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), design basis documents, and consulted with regional staff to identify the design and licensing basis requirements of the reactor vessel. The inspectors performed a detailed review of the as-found condition of the reactor vessel head on November 16, 2011, including data and testing results obtained by the licensee during reactor vessel disassembly following the event. The inspectors also reviewed operator logs and plant computer data. The inspectors performed a walk-down of the reactor vessel head prior to system disassembly to assess material condition of major system components.

b. Observations

FSAR Section 5.3.3.1.1.1.a, Safety Design Basis, states that the reactor vessel and appurtenances were designed to withstand adverse combinations of loadings and forces resulting from operation under abnormal and accident conditions.

FSAR Section 5.3.3.1.2.1, Reactor Vessel Description, states that the vessel top head is secured to the reactor vessel by studs, nuts, and bushings which are designed to be tightened with a stud tensioner. The vessel flanges are sealed by two concentric, silver plated or jacketed seal rings designed for no detectable leakage through the inner or outer seal at any operating condition, including hydrostatic test pressure and heating to operating pressure and temperature at a maximum rate of 100°F/hr. To detect a lack of seal integrity, a one-inch vent tap is provided in the area between the two seal rings, and a monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal. A one-inch tap is also provided in the area outside the outer seal ring for use in monitoring leakage.

The inspectors determined that the reactor vessel was not able to meet its design basis function with the as-found condition. During reactor vessel reassembly, the reactor head studs were not properly tensioned, which allowed leakage of approximately 10 gpm past both the inner and outer seals as reactor temperature and pressure increased. In addition, the one-inch vent taps did not indicate leakage past the seals due to the lack of differential pressure between the seals. The licensee's failure to properly reassemble the RPV head following the Unit 2 maintenance outage is documented in section 4OA5.1 of this report.

.3 Assess the tensioning method for the head studs, the training provided to maintenance, and quality control inspectors for this evolution.

a. Inspection Scope

The inspectors reviewed procedure 0SMP-RPV502, Reactor Vessel Reassembly, Rev. 16, the SEMS III Stud Elongation measurement system vendor manual, and the Tensor AB reactor vessel stud tensioner vendor manual specific to reassembly of the reactor vessel and tensioning of the reactor vessel studs to compare to the licensee's actions taken on November 13, 2011, during reactor vessel reassembly. The inspectors also reviewed training lesson plans and personnel qualifications related to both general and specific training for reactor vessel reassembly. The inspectors interviewed maintenance and quality control personnel to assess the knowledge level and adequacy of the training.

b. Observations

The inspectors determined that the planned tensioning method for the head studs was adequate, however, a combination of no formal training and inadequate just-in-time training contributed to the licensee's failure to properly tension the reactor head studs.

The inspectors interviewed licensee training personnel and found that a formal refueling training qualification for reactor vessel disassembly and reassembly had not been conducted since 2000 per lesson plan ME501B. Maintenance began conducting pre-outage information training; however this was not tracked as a formal qualification. Nine of the twelve personnel who performed reactor vessel reassembly on November 13, 2011, did not have the formal qualification to perform the work. Subsequent investigation by the licensee revealed that this qualification training for refueling personnel is still being conducted at other Progress Energy plants and that the qualification needs to remain active. Procedure TRN-NGCC-1000, Conduct of Training, required training be conducted per the Biennial Period Training Matrix. The training matrix required that refueling floor personnel receive initial qualification (MB81) for reactor vessel reassembly per Lesson Plan ME501B. However, the qualification for ME501B has not been provided since 2000.

The inspectors noted that the licensee conducted informal just-in-time training prior to the Fall 2011 Unit 2 outage. This training covered reactor vessel disassembly and reassembly but did not specifically focus on stud tensioning. A separate SEMS III table-top training session was conducted prior to the Spring 2011 Unit 2 refueling outage to describe operation of the SEMS III device for measuring stud elongation, but was not conducted for the Fall 2011 outage. Seven of the mechanics who performed the reactor vessel reassembly during the Fall 2011 Unit 2 outage received all the just-in-time training and two received the SEMS III table-top training. The remainder did not. The use of the SEMS III measuring device was introduced and successfully used during the Spring 2011 Unit 2 refueling outage. However, the use and interpretation of the tool was not understood during the Fall 2011 outage which resulted in measurement errors that led to the failure of the maintenance crew to recognize that the reactor vessel studs were not properly tensioned. The inspectors also determined that the QC inspector for the job did not receive any specific training related to the use of the SEMS III measuring device.

In conclusion, the licensee did not conduct a specific qualification training course as required by procedure TRN-NGCC-1000, Conduct of Training. Personnel received a combination of general mechanical training and some just-in-time training prior to the Fall 2011 Unit 2 outage, however, this informal training conducted by the licensee did not prevent the refueling team from inadequately tensioning the reactor vessel studs and incorrectly performing stud elongation measurements. The licensee's failure to follow TRN-NGCC-1000, Conduct of Training is documented in section 4OA5.1 of this report.

.4 Assess the data and procedures from the last Unit 1 refueling outage to determine if the head tensioning process was completed correctly.

a. Inspection Scope

The inspectors interviewed personnel and reviewed station documents related to the previous Unit 1 refueling outage and the previous Unit 2 refueling outage to determine if the head tensioning process was completed correctly at that time.

b. Observations

The inspectors determined through review of procedure 0SMP-RPV502, Reactor Vessel Reassembly, Rev. 12, that the head tensioning process was completed correctly for Unit 1 during the previous refueling outage in April 2010. Specifically, RPV Head Stud Tensioning Data Table in Attachment 1 was correctly completed and all data for stud elongation was within the procedural requirements of 0.045" +/- 0.004". This data also correlated with the documented stud tensioning values in the attachment.

The inspectors also determined through review of procedure 0SMP-RPV502, Rev. 15, that the head tensioning process was completed correctly for Unit 2 during the previous refueling outage in April 2011.

.5 <u>Assess the completed outage procedures for head tensioning to determine if all of the verifications and quality control hold points were completed prior to mode changes.</u>

a. <u>Inspection Scope</u>

The inspectors reviewed licensee documents, interviewed personnel, and attended a human performance review board to determine why the reactor vessel head was not properly tensioned and whether all of the verifications and quality control hold points were completed prior to mode changes.

b. <u>Observations</u>

The inspectors conducted a review of procedure 0SMP-RPV502, Reactor Vessel Reassembly, Section 7.15, RPV Head Stud Tensioning, in order to determine what actions were taken by the refueling team to result in the improper tensioning of the reactor vessel head. The inspectors determined that two significant errors, regarding the use of digital instrumentation by the team, combined to allow the improper tensioning to go unnoticed.

The inspectors reviewed Step 7.15.5, which provided guidance on the tensioning sequence and values for the vessel studs. Through interviews, it was determined that personnel operating the Tensor AB stud tensioning machine incorrectly assumed that the digital instrumentation was displaying a factor of ten times the actual pressure (in psi). Although the digital display had the ability to display five digits, only the first four digits displayed a numerical value as pressure was increased. Once pressure increases beyond 9,999 psi, the fifth digit illuminates. The failure of the team to understand this operation resulted in the team assuming that the first four digits displayed ten times the actual pressure. As a result, instead of pressurizing the tensioning device to 13,000 psi, the team actually pressurized the device to 1,300 psi. This practice also resulted in incorrect data being recorded in procedure 0SMP-RPV502, Attachment 1.

The inspectors also determined that errors were made conducting Step 7.15.7, which provided guidance on using the SEMS III digital measuring system to record vessel stud elongation. The SEMS III device was used to record initial vessel stud measurements prior to stud tensioning. The device stored the initial measurements and was then used to take post-tension stud measurements to determine the elongation of the studs. As the data was gathered, the device displayed values ranging from -0.001” to 0.004” which were outside of the expected stud elongation requirements of 0.045” +/- 0.004” per stud. The refueling team incorrectly assumed that the SEMS III device was displaying the variation of the measurement beyond the 0.045” elongation, when in fact the device was displaying the actual elongation of the vessel studs. The team recorded the values of -0.001” to 0.004” in procedure 0SMP-RPV502, Attachment 1 and also attached a spreadsheet that added 0.045” to each of the elongation measurements, which was used as justification for why the values met the acceptance criteria of the procedure. The data table in Attachment 1 was filled out by the mechanic and a QC inspector verified the data and signed the procedure.

Step 7.15.12 stated, "QC: Verify stud tensioning has been satisfactorily completed by reviewing Attachment 1, pages 3 and 4, and signing RPV Head Stud Tensioning Data Table Attachment 1, Page 5." This step was completed and initialed despite the fact that the studs were not tensioned. Step 7.15.13 stated, "Notify Operations that all RPV head studs are fully tensioned." This step allowed Operations to change from Mode 5 to Mode 4 per 0GP-08, Refueling to Cold Shutdown, Rev. 44. This step was also completed and initialed despite the fact that the studs were not tensioned. In addition, Attachment 1 required a review of data by a Lead Mechanic, QC, and a Maintenance Supervisor. These signatures were incorrectly marked as "N/A" by the team. It is not clear whether this additional review would have helped the team identify that the studs had not been tensioned. The licensee's failure to follow 0SMP-RPV502, Reactor Vessel Reassembly, is documented in section 4OA5.1 of this report.

The inspectors determined that all other verifications and quality control hold points in the procedure, related to head tensioning activities, were completed with no issues.

.6 Assess the condition of the reactor vessel head bolts, the reactor vessel head flange and the o-rings and seating surfaces to determine if damage occurred due to the leakage.

a. Inspection Scope

The inspectors performed a walk-down of the reactor vessel head prior to and following system disassembly to assess material condition of major system components. The inspectors also reviewed licensee documents, video recordings, and data collected during disassembly of the reactor vessel. The inspectors also performed an independent visual assessment of the reactor vessel components to determine if damage occurred due to the leakage.

b. Observations

The inspectors conducted a review of the licensee's activities as well as their assessment documented in Engineering Change (EC) 83647 in order to determine if damage occurred due to the leakage. The licensee developed work instructions to take the following actions to determine the condition of the reactor vessel head bolts, vessel flange, head flange, and o-rings to determine if damage occurred due to the leakage:

- Conducted a video inspection of the head assembly including nuts, washers, and studs prior to disassembly. No damage was noted.

- Obtained gap readings between vessel flange and head flange. The licensee determined that the head was parallel to the flange.

- Verified as-found nut tightness for each stud nut. The licensee was able to rotate 8 nuts by hand, 10 nuts by wrench with no agitation, 31 nuts by wrench and agitation, and 15 nuts by wrench with additional agitation. No nuts required detensioning by the tensioning tool.

- Obtained elongation readings for all studs prior to and after nut loosening. The licensee determined that all measurements were within 0.003”, which indicated that the studs had received very little, if any, tensioning prior to the leakage event.

- Requested AREVA conduct ISI NDE, volumetric examination of all installed studs. The licensee determined that there were no issues identified with the studs.

- Confirmed that washer orientation indicated convex side was facing up following nut removal. The licensee determined that all washers were facing in the correct direction.

- Conducted a video inspection of stud threads and head flange prior to lifting head. The licensee did not identify any visible damage to stud threads.

- Conducted a video inspection of vessel flange and head flange with o-rings following lifting of the head. The licensee determined that there was no damage to the flanges. The licensee considered discoloration on the flanges to be the result of staining of the flange from the silver coating that was plated out from the o-rings during the leakage.

- Conducted UT of eight stud bushings in the vessel flange. The licensee determined that there was no damage to the interior or exterior stud bushing threads.

- Conducted detailed video inspection of o-ring condition including retaining clips and performed o-ring thickness measurements. The licensee identified some damage to o-rings including removal of the silver plating. The o-rings were replaced prior to reactor vessel head reassembly.

- Conducted detailed video inspection of vessel flange. The licensee determined there was no damage caused by the leakage.

Overall, the inspectors determined that the licensee conducted a thorough evaluation of the material condition of the reactor vessel. After reviewing the results of the licensee’s evaluations and performing independent reviews by the inspectors, as well as NRC regional support, the team concluded that no damage to the reactor vessel head bolts, the reactor vessel head flange and seating surfaces occurred due to the leakage.

.7 Assess the test program for verifying reactor coolant system integrity after head installation to determine if the licensee was in compliance with ASME testing requirements.

a. Inspection Scope

The inspectors reviewed ASME testing requirements as well as licensee procedures for verifying reactor coolant system integrity following the Unit 2 maintenance outage.

b. Observations

Through reviews of ASME testing requirements, the inspectors found that the licensee was in compliance with ASME testing requirements for verification of reactor coolant system integrity following the Unit 2 maintenance outage. ASME Article IWA-5000 and IWB-5000, System Pressure Tests requires system leakage tests shall be conducted prior to plant start-up following a refueling outage. IWB-2500 does not require a system leakage test to be performed when the reactor vessel is opened and reclosed during a mid-cycle or maintenance outage (i.e. not the end of cycle refueling outage). In addition, licensee procedure 0PT-80.1, Reactor Pressure Vessel ASME Section XI Pressure Test, has a frequency of once each refueling outage.

Inspectors noted that licensee procedure 0PLP-20, Post Maintenance Program, requires in part that plant equipment shall be tested consistent with their safety functions following maintenance activities or troubleshooting activities that may have impaired proper functioning of the component. The inspectors found that the licensee failed to use the guidance in 0PLP-20 to identify an adequate post maintenance test for the reactor vessel that would have validated vessel integrity following reassembly. The licensee’s failure to follow 0PLP-20, Post Maintenance Program, is documented in section 4OA5.1 of this report.

.8 Assess operator performance during the event to determine if there were earlier indications of RCS leakage prior to reaching mode 2 and seven percent.

a. Inspection Scope

The inspectors reviewed plant procedures, computer data, and other licensee documents, and interviewed personnel to assess operator performance during response to the excessive DWFD leakage. Inspectors compared operators’ actions and reactor instrumentation indications to operating procedure requirements, technical specifications, and emergency action levels.

b. Observations

Operators used the following procedural criteria for evaluation of required actions during the leak hunt:

(1) APP A-04 window 3-2: Annunciator Response Procedure, Drywell Floor Drain Sump Leak Hi. The APP directs operators to check the leak rate and compare to the TS limit.

If the leak rate exceeds the TS limit (5 gpm) and cannot be stopped, then enter AOP-14.0.

Assessment: The first Drywell Floor Drain Sump Leak Hi alarm occurred at approximately 7:00 p.m. on November 15, 2011. Operators appropriately used the APP. Leak rates were calculated and were consistently less than the TS limit until 2:12 a.m. on 11/16/11. Operators were timely in identifying the time at which the TS limit was exceeded.

(2) TS 3.4.4, RCS Operational Leakage. The TS limit of 5 gpm was exceeded at 2:12 a.m. on 11/16/11 (note: the TS limit of < 2 gpm increase in 24 hours is only applicable in mode 1, the unit was in mode 2 at this time). Once the TS limit was exceeded, operators declared an LCO not met (Unidentified Leakage, TS 3.4.4 condition A). Operators understood that they were required to meet the TS requirement to reduce leakage to less than 5 gpm in 8 hours, or be in mode 3 within an additional 12 hours.

Assessment: Operators appropriately used and complied with the TS.

(3) AOP-14.0, Abnormal Primary Containment Conditions. This abnormal operating procedure (AOP) directs operators to monitor drywell conditions, calculate leak rates, evaluate recirculation pump seal parameters, and then shutdown the reactor if leakage exceeds the capacity of the sump pump (approximately 100 gpm).

Assessment: Operators reviewed AOP-14.0 but did not formally enter the AOP. Operators stated that they felt that they had accomplished all of the tasks in AOP-14.0 and that formally declaring that the AOP was entered would not have been of any value. Inspectors noted that specific drywell parameters to be monitored are not listed in the AOP (i.e. no specific instruments). The operators stated that they monitored several temperature points in the drywell, drywell pressure, and drywell atmospheric activity monitors. However, operators did not successfully identify an increasing temperature trend in 92' elevation temperatures or drywell particulate activity readings until approximately 2:30 a.m. on 11/16/11. These parameters exceeded normal values at approximately 12:00 a.m. on 11/16/11. Operators continuously observed bulk drywell temperature (average DW temperature), but this was insufficient to identify a specific leak location.

(4) 0EOP-02-PCCP, Primary Containment Control Procedure. This Emergency Operating Procedure's applicable entry condition is Drywell Average Air Temperature > 150 degrees F.

Assessment: Operators did not meet the entry condition for this emergency operating procedure. Drywell average temperature was approximately 100 degrees F.

(5) 0OI-02.3, Drywell Leakage Control directs operators to shutdown the reactor if drywell floor drain leakage exceeds 4.0 gpm. This procedure directs that the leakage criteria be based on 24 hour leak rate calculations, but also states that the Control Room Supervisor (CRS) may take the actions at any time based on his discretion.

Assessment: 12:00 a.m. leakage rates were calculated to be 3.99 gpm. At approximately 1:00 a.m. the Shift Technical Advisor calculated a leakage rate of “about 4.2 gpm.” However, the CRS did not shutdown the reactor because he felt that this procedure is applicable to 24 hour leak rates that aren’t being actively addressed. He felt the watch team was actively pursuing identification of the leak, and that with the drywell accessible, there was a high likelihood of identifying and correcting the source of the leakage. Inspectors noted that this approach is allowed by the procedure.

(6) 0PEP-02.1, Initial Emergency Actions, requires declaration of an Unusual Event when Unidentified or pressure boundary leakage is > 10 gpm.

Assessment: Operators appropriately declared an Unusual Event when DWFD leakage exceeded 10 gpm.

Overall Operator Assessment: No procedural, TS, or regulatory requirements obligated the operators to shutdown the reactor. Plant procedures and guidance required the operators to identify the cause of the increased leakage. TS 3.4.4 would have required a shutdown eventually if leakage had remained above 5 gpm. Operators made the decision to shut down the reactor when it became apparent that leakage was rapidly increasing.

Operators were actively pursuing identification of the leak throughout the night. Plant Management, including the Operations Manager, was present and actively engaged in decision making. At approximately 7:00 p.m., an automatic start of the DWFD sump pump made operators aware of increased leakage. Since the 8:00 p.m. 4-hour leak rate calculation was 0.1 gpm, a significant increase in leakage occurred between 1600 and 7:00 p.m. on November 15, 2011. Prior to 4:00 p.m., there were no signs of significant DWFD leakage. The small amount of DWFD sump ingress prior to 4:00 p.m. was attributed to condensed atmospheric humidity due to the drywell being ventilated with outside air, and a known packing leak on the B recirculation loop discharge valve. These were reasonable assumptions. Operators were aware that the plan to backseat the valve was being executed by maintenance and the OCC. This valve was backseated at approximately 11:30 p.m.. The 3.99 gpm calculation for DWFD leakage at 12:00 a.m. was a 4-hour average and included 3.5 hours when the recirculation discharge valve was not backseated. The 1:00 a.m. leakage calculation of approximately 4.2 gpm was for the hour from 12:00 a.m. to 1:00 a.m.. This signaled the operators that the leakage was not due to the recirculation pump discharge valve. At 2:12 a.m., the leakage rate was calculated to be 5.88 gpm. At 2:35 a.m., DW 92’ elevation temperatures were noted to be above normal at 240 degrees F and the operators realized that steam was leaking on the 92’ elevation of the drywell. During the time between 1:00 a.m. and 2:35 a.m., operations directed a second DW entry to identify the leak location and to obtain a sump sample for chemical analysis.

Overall operator performance in the identification of the leak was not optimal. For example, slowly rising trends of drywell airborne radioactivity and 92’ elevation temperatures were not recognized for several hours. Several operators stated that because the leak from the recirculation pump discharge valve was identified previously, and because unidentified DWFD leakage during a reactor startup was not uncommon at

Brunswick, they weren't rigorously pursuing other potential causes. However, inspectors noted that operators were attentive to the magnitude and progression of the leak, and took sufficient actions to ensure reactor safety.

.9 Assess the licensee's activities related to the problem investigation performed to date (e.g., root cause analysis, extent of condition, additional equipment failure mechanisms, etc.), including any safety culture aspects.

a. Inspection Scope

The inspectors performed a preliminary review of the licensee investigation team report to assess the licensee's investigation of the failure to properly tension the reactor pressure vessel head.

b. Observations

A root cause evaluation was not completed at the time of the inspection. However, AR 500035 was initiated to perform the root cause evaluation and an extent of condition review. These reviews had not been completed by the licensee at the time of the inspection. The licensee noted that the final extent of condition review will be completed and documented in the cause evaluation process. The team reviewed EC 8364R0 which contained the equipment assessment for the event. The evaluation reviewed is documented in Section 4OA5.

.10 Assess the licensee's actions for previous significant outage events to determine if lessons learned could have prevented the issue.

a. Inspection Scope

The inspectors reviewed corrective actions associated with recent outage events at Brunswick Nuclear Plant to determine if lessons learned could have prevented the failure to properly reassemble the RPV. This review focused on corrective actions associated with the improper loosening of the RPV level instrument reference leg during previous outages.

b. Observations

This licensee's first recent significant outage event occurred during the Unit 2 Spring 2009 outage, when maintenance personnel improperly removed vessel head piping which resulted in a loss of reactor level indication in the control room. Inspectors found that the licensee identified corrective actions to revise 0SMP-RPV501, Reactor Vessel Disassembly, to require that Operations complete swap of vessel level indication prior to disassembly of any head piping. A repeat event occurred during the Unit 1 Spring 2010 outage when maintenance personnel improperly removed vessel head piping which again resulted in a loss of reactor level indication in the control room. The licensee concluded that the previous corrective actions associated with procedural enhancements were insufficient. The inspectors determined that these events and their associated corrective actions were unrelated to the RPV reassembly issue and lessons learned would not have prevented the issue.

4OA5 Other Activities

.1 (Opened) Unresolved Item (URI), Failure to Properly Assemble Reactor Vessel Head Following Maintenance Outage.

Introduction: The inspectors identified an URI associated with the licensee's failures to follow plant procedures and properly reassemble the RPV head following the Unit 2 maintenance outage. These procedural failures resulted in excessive leakage from the Unit 2 reactor vessel on November 16, 2011.

Description: On November 17, 2011, the licensee determined that the reactor head flange was leaking due to inadequate reactor vessel head stud tensioning. Inspectors reviewed the licensee's actions prior to the event and identified examples of improper procedure use and adherence that contributed to the inadequate reactor vessel head stud tensioning.

- Inspectors reviewed the completed "Reactor Vessel Reassembly" procedure (0SMO-RPV502) and determined that the refuel floor team failed to properly pressurize the RPV head stud tensioner to the values specified in 0SMP-RPV502 Attachment 1, which required a tensioner pressure of 13,000 lbs to achieve the desired stud elongation. Specifically, the refuel floor team interpreted an indicated tensioner pressure of 1300 lbs to be 13,000 lbs because the tensioner operators did not know how to correctly interpret the reading on the tensioner display. The RPV studs where under-tensioned due to this error.

- Procedure 0SMO-RPV502, Reactor Vessel Reassembly, step 7.15.12 requires QC to verify stud tensioning has been satisfactorily completed by reviewing and signing RPV head stud tensioning data table Attachment 1. The inspectors also determined that QC failed to verify proper RPV stud elongation in accordance with stud elongation values provided in 0SMP-RPV502. Although the verification was signed, none of the required stud elongation readings matched the acceptance criteria

- Procedure TRN-NGCC-1000, Conduct of Training, requires training be conducted per the biennial period Training Matrix. The training matrix requires that refueling floor personnel receive initial qualification (MB81) for reactor vessel reassembly per Lesson Plan ME501B. However, the qualification for ME501B has not been maintained by maintenance personnel performing RPV disassembly and reassembly, and the training associated with qualifications has not been updated to include current practices/tools or provided to any workers since 2000. As a result, nine of the twelve refuel floor personnel performing reactor vessel reassembly on November 13, 2011, did not have the refuel floor support training qualification (MB81) and failed to properly tension the reactor studs upon reassembly of the reactor vessel.

- 0PLP-20, Post Maintenance Testing, requires "plant equipment shall be tested consistent with their safety functions following maintenance activities that may have impaired proper functioning of the component." The team determined that the licensee failed to specify an adequate PMT to test the pressure retaining capability of the RPV head.

Summary: This issue is unresolved pending completion of and review of the licensee's root cause evaluation. The URI for this issue is identified as 05000324/2011013-01, Failure to Properly Assemble Reactor Vessel Head Following Maintenance Outage.

4OA6 Meetings, including Exit

The inspectors presented the inspection results to Mr. Annacone and other members of licensee management on December 15, 2011. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary information. The licensee did not identify any proprietary information.

ATTACHMENT: SUPPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
M. Annacone, Site Vice President
A. Brittain, Security Manager
J. Burke, Engineering Director
P. Dubrouillet, Training Manager
C. Dunsmore, Shift Operations
K. Gerald, Maintenance Manager
S. Gordy, Operations Manager
L. Grzeck, Lead Engineer - Technical Support
K. Hill, Control Room Supervisor
R. Ivey, Nuclear Oversight Services Manager
J. Johnson, Environmental and Radiological Controls Manager
P. Mentel, Support Services Manager
J. Miller, Operation Shift Manager
A. Pope, Licensing and Regulatory Affairs Supervisor
T. Sherrill, Technical Support

NRC personnel:
Randall A. Musser, Chief, Reactor Projects Branch 4, Division of Reactor Projects Region II

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000324/2011013-01	URI	Failure to Properly Assemble Reactor Vessel Head Following Maintenance Outage

Closed

None

LIST OF DOCUMENTS REVIEWED

Procedures
NOS-NGGC-0500, Quality Assurance Hold Point Procedure, Rev. 0
PRO-NGGC-0200, Procedure Use and Adherence, Rev. 14
0GP-08, Refueling to Cold Shutdown, Rev. 44
0SMP-RPV501, Reactor Vessel Disassembly, Rev. 16
0SMP-RPV502, Reactor Vessel Reassembly, Revs. 12-17
0PLP-20, Post Maintenance Testing Program, Rev. 380
PRO-NGGC-0204, Procedure Review and Approval, Rev. 21
TRN-NGGC-1000, Conduct of Training, Rev. 5
APP A-04, Annunciator Response Procedure
AOP-14.0, Abnormal Primary Containment Conditions
0EOP-02-PCCP, Primary Containment Control Procdure
0OI-02.3, Drywell Leakage Control
0PEP-02.1, Initial Emergency Actions

ARs Reviewed
00500035
00501113
00500920
00500538
00500540
00500011
00500593
00500919
50039248
00500392
00500470
00500519
00500541
00500590
00500591
00500690
00500763
00500766
00500869
00500932
00500986
00501116
00501226
00501236
00501308
00501313
00501392
00501452
00501424
00322354

00383779

Work Orders
WO 01582935-01
WO 01324426-01
WO 01619957-01
WO 01984574-25

Other
FP-86812, SEMS III System User Guide & Operation Manual Model Number: 10-08742, Rev. A
FP-85239, Tensor AB Reactor Vessel Stud Tensioner and Carousel/Lift Rig, Rev. G
MEF01G, Bolted Joint Assembly Training, Rev. 1
MEC102B, Mechanical Maintenance Continuing Training, Rev. 1
MEC081B, Mechanical Continuing Training, Rev. 0
ME501B, Refueling Support Overview Training
ASME Article IAW-500, System Pressure Tests
MEC0001B, Vessel Head Stud Tensioning and Elongation Measuring Training
LOT-JITT-2011-07A, Licensed Operator Just-in-Time Training
LOT-JITT-2011-07BR2, Licensed Operator Just-in-Time Training
Dominion Engineering Calculation C-3526-00-01, Evaluation of Brunswick Reactor Pressure Vessel Pressurization with Untensioned Studs

SPECIAL INSPECTION CHARTER TO EVALUATE BRUNSWICK UNIT 2 REACTOR PRESSURE VESSEL HEAD LEAKAGE

A. Basis

On November 16, 2011, at 2:08 a.m., Brunswick Nuclear Plant Unit 2 calculated a drywall floor drain leak rate of 5.88 gpm following several hours of gradually rising floor drain leakage during a plant startup. Technical Specification 3.4.4 A was entered requiring floor drain leakage to be restored below 5 gpm within 8 hours. At 2:53 a.m., the calculated leak rate was 10.11 gpm. At 3:01 a.m., a NOUE was declared for unidentified leakage exceeding 10 gpm. At 3:09 a.m., the licensee initiated a manual reactor scram from approximately 7% power. Following the scram, reactor pressure was decreased and the unidentified leak rate dropped below 10 gpm within 1 hour and less than 5 gpm within 2 hours. The leak rate at 6:14 a.m. was 3.82 gpm with reactor pressure at 228 psig.

The NOUE was exited at 8:15 a.m. on November 16, 2011, when leakage could be maintained below 10 gpm due to decreasing pressure. The unit was cooled down and reached cold shutdown at 2:38 p.m. on November 16, 2011.

On November 17, 2011, the licensee determined that the reactor head flange was leaking due to inadequate reactor vessel head stud tensioning. The licensee had access to 15 of 64 head studs. Twelve of the 15 stud nuts could be rotated by hand. The specific issues of concern are:

- Was the reactor vessel head, stud, and flange damaged as a result of the head lifting after the vessel was pressurized?
- Was operator response during the event adequate?
- Was the stud tensioning process implemented properly?
- Were ASME vessel pressure testing requirements met?

In accordance with MD 8.3, "NRC Incident Investigation Program," deterministic and conditional risk criteria were used to evaluate the level of NRC response for this operational event. One deterministic criterion was met. The issue involved a significant loss of integrity of the fuel, primary coolant pressure boundary, or primary containment boundary of a nuclear reactor. The updated Conditional Core Damage Probability (CCDP) for the event was in the overlap region of a Special Inspection and an Augmented Inspection Team. Following discussion with NRR, a special Inspection was deemed appropriate based on the limited technical and operational complexity of this event (flange leak).

Accordingly, the objectives of the inspection are to: (1) determine the facts surrounding the degraded condition of the Brunswick reactor vessel head; (2) evaluate the licensee's response to this condition; and, (3) evaluate corrective actions.

B. Scope

To accomplish these objectives, the following will be performed:

- Develop a timeline associated with this event.

- Assess the ability of the reactor vessel to meet its design basis functions with the as-found condition.

- Assess the tensioning method for the head studs, the training provided to maintenance, and quality control inspectors for this evolution.

- Assess the data and procedures from the last Unit 1 refueling outage to determine if the head tensioning process was completed correctly.

- Assess the completed outage procedures for head tensioning to determine if all of the verifications and quality control hold points were completed prior to mode changes.

- Assess the condition of the reactor vessel head bolts, the reactor vessel head flange and the o-rings and seating surfaces to determine if damage occurred due to the leakage.

- Assess the test program for verifying reactor coolant system integrity after head installation to determine if the licensee was in compliance with ASME testing requirements.

- Assess operator performance during the event to determine if there were earlier indications of RCS leakage prior to reaching mode 2 and seven percent.

- Assess the licensee’s activities related to the problem investigation performed to date (e.g., root cause analysis, extent of condition, additional equipment failure mechanisms, etc.), including any safety culture aspects.

- Assess the licensee’s actions for previous significant outage events to determine if lessons learned could have prevented the issue.

- Assess the significance of additional issues and provide recommendations to Region II if escalation to an augmented inspection is warranted.

- Document the inspection findings and conclusions in an inspection report within 45 days of the inspection.

- Conduct an exit meeting.

C. <u>Guidance</u>

Inspection Procedure (IP) 93812, “Special Inspection,” provides additional guidance to be used during the conduct of the inspection. Your duties will be as described in IP 93812 and should emphasize fact-finding in its review of the circumstances surrounding the degraded condition. Safety or security concerns identified that are not directly related to the event should be reported to the Region II office for appropriate action.

You will report to the site, conduct an entrance, and begin inspection no later than November 21, 2011. It is anticipated that the on-site portion of the inspection will be completed during the following days November 21-23, and November 28 - December 2. An initial briefing of Region II management will be provided the second day on-site at approximately 4:00 p.m. In accordance with IP 93812, you should promptly recommend a change in inspection scope or escalation if information indicates that the assumptions utilized in the MD 8.3 risk analysis were not accurate. A report documenting the results of the inspection should be issued within 45 days of the completion of the inspection. The report should address all applicable areas specified in section 3.02 of IP 93812. At the completion of the inspection you should provide recommendations for improving the Reactor Oversight Process baseline inspection procedures and the Special Inspection process based on any lessons learned.