UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

February 24, 2011

Mr. Paul A. Harden
Site Vice President
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Mail Stop A-BV-SEB1
P.O. Box 4, Route 168
Shippingport, PA 15077

SUBJECT: BEAVER VALLEY POWER STATION, UNIT NO. 2 - ISSUANCE OF AMENDMENT REGARDING THE REVISED STEAM GENERATOR INSPECTION SCOPE USING F* INSPECTION METHODOLOGY (TAC NO. ME3498)

Dear Mr. Harden:

The Commission has issued the enclosed Amendment No. 172 to Renewed Facility Operating License No. NPF-73 for the Beaver Valley Power Station, Unit No. 2 (BVPS-2). This amendment consists of changes to the Technical Specifications in response to your application dated February 26, 2010, as supplemented by letters dated November 10, 2010, and January 26, 2011.

The amendment revises the scope of the steam generator (SG) tube inspections for the portion of the tube in the tubesheet on the cold-leg side of the SG by using the F* methodology.

A copy of the related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Nadiyah S. Morgan, Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-412

Enclosures:
1. Amendment No. 172 to NPF-73
2. Safety Evaluation

cc w/encls: Distribution via Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

OHIO EDISON COMPANY

THE TOLEDO EDISON COMPANY

DOCKET NO. 50-412

BEAVER VALLEY POWER STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 172
License No. NPF-73

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by FirstEnergy Nuclear Operating Company, et al. (the licensee), dated February 26, 2010, as supplemented by letters dated November 10, 2010 and January 26, 2011, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-73 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 172, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto are hereby incorporated in the license. FENOC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Nancy L. Salgado

Nancy L. Salgado, Chief
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the License and Technical Specifications

Date of Issuance: February 24, 2011

ATTACHMENT TO LICENSE AMENDMENT NO. 172

FACILITY OPERATING LICENSE NO. NPF-73

DOCKET NO. 50-412

Replace the following pages of Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and include lines in the margin indicating the areas of change.

Remove	Insert
License page 4	License page 4
5.5-10	5.5-10
5.5-11	5.5-11
5.5-12	5.5-12
5.6-6	5.6-6

(b) Further, the licensees are also required to notify the NRC in writing prior to any change in: (i) the term or conditions of any lease agreements executed as part of these transactions; (ii) the BVPS Operating Agreement, (iii) the existing property insurance coverage for BVPS Unit 2, and (iv) any action by a lessor or others that may have adverse effect on the safe operation of the facility.

C. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations set forth in 10 CFR Chapter 1 and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

FENOC is authorized to operate the facility at a steady state reactor core power level of 2900 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 172, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto are hereby incorporated in the license. FENOC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

5.5 Programs and Manuals

5.5.5.2 Unit 2 Steam Generator (SG) Program (continued)

5. The F* methodology, as described below, may be applied to the expanded portion of the tube in the hot-leg or cold-leg tubesheet region as an alternative to the 40% depth based criteria of Specification 5.5.5.2.c.1:

   a) Tubes with no portion of a lower sleeve joint in the hot-leg or cold-leg tubesheet region shall be repaired or plugged upon detection of any flaw identified within 3.0 inches below the top of the tubesheet or within 2.22 inches below the bottom of roll transition, whichever elevation is lower. Flaws located below this elevation may remain in service regardless of size.

   b) Tubes which have any portion of a sleeve joint in the hot-leg or cold-leg tubesheet region shall be plugged upon detection of any flaw identified within 3.0 inches below the lower end of the lower sleeve joint. Flaws located greater than 3.0 inches below the lower end of the lower sleeve joint may remain in service regardless of size.

   c) The F* methodology cannot be applied to the tubesheet region where a laser or TIG welded sleeve has been installed.

d. Provisions for SG Tube Inspections

-NOTE-

The requirement for methods of inspection with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube does not apply to the portion of the original tube wall adjacent to the nickel band (the lower half) of the lower joint for the repair process that is discussed in Specification 5.5.5.2.f.3. However, the method of inspection in this area shall be a rotating plus point (or equivalent) coil. The SG tube repair criterion of Specification 5.5.5.2.c.3 is applicable to flaws in this area.

Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In tubes repaired by sleeving, the portion of the original tube wall between the sleeve's joints is not an area requiring re-inspection. In addition to meeting the requirements of d.1, d.2, d.3, d.4, d.5 and d.6 below, the inspection

5.5 Programs and Manuals

5.5.5.2 Unit 2 Steam Generator (SG) Program (continued)

scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one interval between refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one interval between refueling outages (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

4. Indications left in service as a result of application of the tube support plate voltage-based repair criteria (Specification 5.5.5.2.c.4) shall be inspected by bobbin coil probe during all future refueling outages.

   Implementation of the steam generator tube-to-tube support plate repair criteria requires a 100-percent bobbin coil inspection for hot-leg and cold-leg tube support plate intersections down to the lowest cold-leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold-leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20-percent random sampling of tubes inspected over their full length.

5. When the F* methodology has been implemented, inspect 100% of the inservice tubes in the hot-leg tubesheet region with the objective of detecting flaws that may satisfy the applicable tube repair criteria of Specification 5.5.5.2.c.5 every 24 effective full power months or one interval between refueling outages (whichever is less).

5.5 Programs and Manuals

5.5.5.2 Unit 2 Steam Generator (SG) Program (continued)

6. For Alloy 800 sleeves: The parent tube, in the area where the sleeve-to-tube hard roll joint (lower joint) and the sleeve-to-tube hydraulic expansion joint (upper joint) will be established, shall be inspected prior to installation of the sleeve. Sleeve installation may proceed only if the inspection finds these regions free from service induced indications.

e. Provisions for monitoring operational primary to secondary LEAKAGE

f. Provisions for SG Tube Repair Methods

Steam generator tube repair methods shall provide the means to reestablish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair. All acceptable tube repair methods are listed below.

1. ABB Combustion Engineering TIG welded sleeves, CEN-629-P, Revision 02 and CEN-629-P Addendum 1.

2. Westinghouse laser welded sleeves, WCAP-13483, Revision 2.

3. Westinghouse leak-limiting Alloy 800 sleeves, WCAP-15919-P, Revision 2. All Alloy 800 sleeves shall be removed from service by the spring of 2017 Unit 2 refueling outage (2R19).

5.5.6 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables,

b. Identification of the procedures used to measure the values of the critical variables,

c. Identification of process sampling points,

d. Procedures for the recording and management of data,

e. Procedures defining corrective actions for all off control point chemistry conditions, and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.6 Reporting Requirements

5.6.6.2 Unit 2 Steam Generator Tube Inspection Report (continued)

b. If indications are identified that extend beyond the confines of the tube support plate.

c. If indications are identified at the tube support plate elevations that are attributable to primary water stress corrosion cracking.

4. A report shall be submitted within 90 days after the initial entry into MODE 4 following an outage in which the F* methodology was applied. As applicable, the report shall include the following hot-leg and cold-leg tubesheet region inspection results associated with the application of F*:

a. Total number of indications, location of each indication, orientation of each indication, severity of each indication, and whether the indications initiated from the inside or outside surface.

b. The cumulative number of indications detected in the tubesheet region as a function of elevation within the tubesheet.

c. The projected end-of-cycle accident-induced leakage from tubesheet indications.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 172 TO RENEWED

FACILITY OPERATING LICENSE NO. NPF-73

FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

OHIO EDISON COMPANY

THE TOLEDO EDISON COMPANY

BEAVER VALLEY POWER STATION, UNIT NO. 2

DOCKET NO. 50-412

1.0 INTRODUCTION

By application dated February 26, 2010 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML100630422), as supplemented by letters dated November 10, 2010 (ADAMS Accession No. ML103370240) and January 26, 2011 (ADAMS Accession No. ML110320242), FirstEnergy Nuclear Operating Company (FENOC, the licensee), requested changes to the Technical Specifications (TSs) for Beaver Valley Power Station, Unit No. 2 (BVPS-2). The supplements dated November 10, 2010, and January 26, 2011, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the Nuclear Regulatory Commission (NRC) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on January 11, 2011 (76 FR 1648).

The changes would revise the scope of the steam generator (SG) tube inspections for the portion of the tube in the tubesheet on the cold-leg side of the SG by using the F* methodology. Previously, the NRC staff approved the use of the F* methodology for use on the hot-leg side of the SGs by letter dated September 27, 2006 (ADAMS Accession No. ML062580419). The existing TS 5.5.5.2.c.1 states that, "tubes found by inservice inspection (ISI) to contain a flaw in a non-sleeved region with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged or repaired except if permitted to remain inservice through application of the alternate repair criteria discussed in Specification 5.5.5.2.c.4 or 5.5.5.2.c.5." TS 5.5.5.2.c.5 currently specifies that the 40 percent depth criterion for tube repair does not need to be applied in the hot-leg tubesheet region below the "F* distance" in the tubesheet. The license amendment request (LAR) adds the cold-leg tubesheet region to hot-leg region already specified in TS 5.5.5.2.c.5. According to the F* methodology in TS 5.5.5.2.c.5, flaws below the F* distance may remain in service regardless of size. Implementing the F* methodology also eliminates the need to inspect the portion of the tube within the hot-leg and cold-leg tubesheet regions below the F* distance, since the inspection provision in TS 5.5.5.2.d requires that tubes be inspected with the objective of detecting flaws that may satisfy the applicable tube repair criteria. With no repair criteria to satisfy, the portion of the tube below the F* distance is not subject to the inspection provision.

The change will add a TS inspection requirement for the cold-leg side of the tubesheet that is different than the inspection requirement for the hot-leg side of the tubesheet. The requirement stipulates that if the Degradation Assessment requires inspection of the cold-leg tubesheet region, the F* methodology shall be implemented and the initial sample population shall be at least a 20 percent random sample of the in-service tubes over for the entire F* distance. Expansion of the initial sample size shall be as defined in the Degradation Assessment. The change also adds reporting of the cold-leg tubesheet region inspection results (associated with the F* methodology) to the reporting requirement of the hot-leg tubesheet region inspection results, currently required in TS Section 5.6.6.2.4.

2.0 REGULATORY EVALUATION

2.1 Description of System

Steam generator tubes function as an integral part of the reactor coolant pressure boundary and, in addition, serve to isolate radiological fission products in the primary coolant from the secondary coolant and the environment. Because of the importance of SG tube integrity, the NRC requires the performance of periodic ISIs of SG tubes. These inspections detect, in part, flaws in the tubes resulting from interaction with the SG operating environment. ISIs may also provide a means of characterizing the nature and cause of any tube flaws so that corrective measures can be taken. Tubes with flaws that exceed the tube repair criteria specified in a plant's TS are removed from service by plugging or are repaired by sleeving. The TSs provide the acceptance criteria related to the results of SG tube inspections. The requirements for the inspection of SG tubes are intended to ensure that this portion of the reactor coolant system maintains its integrity. Tube integrity means that the tubes are capable of performing these functions in accordance with the plant design and licensing basis. Tube integrity includes both structural and leakage integrity. Structural integrity refers to maintaining adequate margins against gross failure, rupture, and collapse of the SG tubes. Leakage integrity refers to limiting primary-to- secondary leakage during normal operation, plant transients, and postulated accidents. These limits ensure the radiological dose consequences associated with any leakage are within acceptable limits and they limit the frequency of SG tube ruptures.

2.2 Regulatory Requirements and Guidance

In reviewing requests of this type, the NRC staff verifies that a methodology exists that maintains the structural and leakage integrity of the tubes consistent with the plant design and licensing basis. This includes verifying that the applicable General Design Criteria (GDC), e.g., GDCs 14 and 32, contained in Appendix A of Part 50 to Title 10 of the *Code of Federal Regulations* (10 CFR) and the performance criteria in the plant TSs are satisfied. The NRC staff's evaluation is based, in part, on ensuring that the structural margins inherent in Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR [pressurized-water reactor] SG Tubes," are maintained. The NRC staff's evaluation also includes verifying that a conservative methodology exists for determining the amount of primary-to-secondary leakage that may occur during design-basis accidents (DBAs). The amount of leakage is limited to ensure that offsite and control room dose criteria are met. The radiological dose criteria are specified, in part, in 10 CFR Part 100, in 10 CFR 50.67, and in GDC 19 of Appendix A to 10 CFR Part 50.

The NRC approved a similar redefinition of a tube inspection for the original SGs at the Kewaunee Power Station in 1996 (NUDOCS 9609230197), for the Joseph M. Farley Plant, Unit 2 (Farley Unit 2) in 1996 (NUDOCS 9610220228), for the Comanche Peak Steam Electric Station, Unit 1 in 1999 (NUDOCS 9909030072), for the Watts Bar Nuclear Plant, Unit 1 in 2000 (ADAMS Accession No. ML003748725) and others. In each case, plant-specific repair criteria were determined.

3.0 TECHNICAL EVALUATION

3.1 Background

BVPS-2 is a 3-loop, Westinghouse-designed plant with Model 51M SGs. Each SG contains 3376 mill-annealed Alloy 600 tubes with an outside diameter of 0.875-inch and a wall thickness of 0.050-inch. The tubes in each SG are supported by horizontal support plates with drilled holes. All tube support material is carbon steel. The tubes were expanded with a mechanical rolling process (hardroll) at both ends for the full length of the tubesheet (21 inches). A weld joins the tube end to the cladding on the primary face of the tubesheet, providing a leak-tight boundary and resistance to tube pullout. The hardroll process produces an interference fit between the tube and tubesheet which can also provide resistance to tube pullout. The transition from the expanded portion of the tube to the unexpanded portion of the tube is referred to as the roll transition. Prior to operation, the internal surfaces of the tubes on the hot-leg side of the tubesheet were shotpeened, which applies a compressive stress that generally increases resistance to stress-corrosion cracking. The existing TSs for BVPS -2 permit the installation of three types of sleeves in order to repair flaws. The sleeves have both upper and lower joints that form the interface with the parent tube.

The tube-to-tubesheet joint consists of the tube, which is roll-expanded against the bore of the tubesheet, the tube-to-tubesheet weld located at the tube end, and the tubesheet. Typically, plants designed the tube-to-tubesheet joint as a welded joint rather than a friction or expansion joint. That is, the weld itself was designed as a pressure boundary element, and it was designed to transmit the entire end cap pressure load during normal and DBA conditions from the tube to the tubesheet with no credit taken for the friction developed between the roll-expanded tube and the tubesheet. In addition, the weld makes the joint leak tight.
The existing inspection and repair requirements in the plant TSs do not take into account the reinforcing effect of the tubesheet on the external surface of the expanded tube. Nonetheless, the presence of the tubesheet constrains the tube and complements tube integrity in that region, by preventing tube deformation beyond the expanded outside diameter of the tube. The resistance to both tube rupture and tube collapse is significantly enhanced by the tubesheet reinforcement. In addition, the proximity of the tubesheet to the expanded tube significantly reduces the leakage from any through-wall defect.

Based on these considerations, power reactor licensees have proposed, and the NRC has approved, alternate repair criteria for SG tube defects located in the lower portion of the tubesheet, when these defects are a specific distance below the expansion transition or the top of the tubesheet (TTS), whichever is lower. The F* methodology defines a distance, referred to as the F* distance, such that any type or combination of flaws below this distance (including flaws in the tube-to-tubesheet weld) is considered acceptable. That is, even if inspections below the F* distance identify flaws, the regulatory requirements pertaining to tube structural and leakage integrity would be met provided there were no significant flaws within the F* distance. The F* distance is measured from the TTS or the bottom of the roll transition (BRT), whichever is lower.

Determination of the F* distance includes a nondestructive examination (NDE) uncertainty value of 0.25 inch, which was established in the F* evaluation for Farley Unit 2 and subsequently approved as part of the staff's safety evaluation for that repair criteria. It also includes an adjustment for the location of the BRT in relation to the TTS. The value of F* calculated for structural and leakage integrity, without adjustments for NDE uncertainty and BRT location, is called the F* length. That is, the F* distance is the sum of the F* length, the NDE uncertainty, and the BRT adjustment.

The F* evaluation presented in WCAP-16385, "F* Tube Plugging Criterion For Tubes With Degradation In The Tubesheet Roll Expansion Region Of The Beaver Valley Unit 2 Steam Generators," Revision 1 (ADAMS Accession No. ML051040084), was performed for the expected operating conditions at BVPS-2 (including an 8-percent extended power uprate (EPU) which was subsequently approved by the NRC on July 19, 2006) and for DBAs. The F* value determined for the limiting faulted condition (SG feedwater line break (FLB)) bounds the current normal operating conditions and EPU conditions, with up to 22 percent tube plugging.

The F* analysis considered the forces acting to pull the tube out of the tubesheet (i.e., from the internal pressure in the tube) and the forces acting to keep the tube in place. These latter forces are a result of friction and the forces arising from (1) the residual preload from the installation (rolling) process, (2) the differential thermal expansion between the tube and the tubesheet, and (3) internal pressure in the tube within the tubesheet. In addition, the effects of tubesheet bow, due to pressure and thermal differentials across the tubesheet, were considered since this bow causes dilation of the tubesheet holes from the secondary face to approximately the midpoint of the tubesheet and reduces the ability of the tube to resist pullout. The amount of tubesheet bow varies as a function of radial position, with locations near the periphery experiencing less bow. The effects of tubesheet hole dilation were analyzed using the worst-case hole (location) in the tubesheet.

3.2 FENOC Proposal

The licensee's basis for revising the criteria for tube repair within the hot-leg tubesheet region is documented in its LAR, in WCAP-16385, Revision 1, and in the November 10, 2010, and January 26, 2011, supplemental letters. These documents also referred to WCAP-11306, "Tubesheet Region Plugging Criterion for the Alabama Power Company Farley Nuclear Station Unit 2 Steam Generators," Revision 2, April 1987, which describe the analysis and testing performed to justify a similar modification in the tube repair criteria for the Farley Nuclear Station, Unit 2.

For tubes with no portion of a lower sleeve joint in the hot-leg tubesheet region, TS 5.5.5.2.c.5.a specifies that the tube must be repaired or plugged if any flaw is detected within 3 inches below the TTS or 2.22 inches below the BRT, whichever elevation is lower. For tubes which have any portion of a sleeve joint in the hot-leg tubesheet region, TS 5.5.5.2.c.5.b specifies that the tube must be plugged if any flaw is detected within 3 inches below the lower end of the lower sleeve joint. Any flaw located below the elevations specified in proposed TSs 5.5.5.2.c.5.a and 5.5.5.2.c.5.b would be allowed to remain in service regardless of size.

The following sections summarize the NRC staff's evaluation of the proposed BVPS-2 F* proposal in terms of maintaining SG structural and leakage integrity.

3.3 Tube Structural Integrity

The amendment would permit tubes with flaws to remain in service; therefore, the licensee must demonstrate that the tubes kept in service using the F* methodology will maintain adequate structural integrity for the period of time between inspections. Tube rupture and pullout of a tube from the tubesheet are the two potential credible modes of structural failure considered for tubes returned to service under the F* methodology.

In order for a tube to rupture, a flaw would need to grow above the tubesheet's secondary face. If the entire flaw remains within the tubesheet, the reinforcement provided by the tubesheet will prevent tube rupture. The F* methodology proposed by the licensee for BVPS-2 requires an inspection of the top portion of the tube within the hot-leg tubesheet and the plugging of any flaws in this region. Therefore, any known flaws remaining in service following the inspections will be located a minimum of 3 inches below the TTS or the lower joint of a sleeve. Industry operating experience shows flaw growth rates within the tubesheet are well below those necessary to propagate a flaw from 3 inches below the TTS to outside the tubesheet in one operating cycle (typically 18 months). Therefore, it is unlikely that any of these flaws will grow in an axial direction and extend outside the tubesheet during one operating cycle. Similarly, it is unlikely that a flaw would propagate upward to a sleeve joint from 3 inches below the joint during one operating cycle. Thus, tube burst is precluded for these flaws due to the reinforcement provided by the surrounding tubesheet.

In the event that undetected flaws are present in the F* distance, or that new flaws initiate in the F* distance during the operating cycle following an inspection, it is possible that these flaws could grow in the axial direction and extend outside the tubesheet. As a result, the NRC staff considered the conditions that would be necessary to structurally fail a tube with this type of flaw. Steam generator tube rupture is primarily a function of flaw geometry, the differential pressure across the tube wall, and the flaw location. Axial through-wall flaws may result in a tube failing to maintain adequate margins for burst under all operating conditions. However, this would require the flaws to exceed a certain length, typically on the order of one-half inch or longer, and have no external restraint (i.e., occur in the free span). Partially through-wall flaws would require additional length (beyond the one-half inch postulated above) in order to become susceptible to spontaneous rupture based on empirical models for tube burst. Thus, these flaws would have to extend a significant distance above the tubesheet to degrade the margins of structural integrity for the affected tube (i.e., tubes with undetected flaws slightly below the TTS).

In addition, constraining a flaw at one end by the tubesheet would further elevate the burst pressure of this tube (compared to an identical flaw with no constraint). Flaw growth rates necessary for undetected or newly initiated flaws to reach a critical flaw size are unlikely to occur given the inspections that are required to be performed. Therefore, flaws remaining in service under either of the two scenarios described above should result in the tube(s) maintaining adequate margins for tube burst.

The other postulated structural failure mode for tubes remaining in service using the F* methodology is pullout of the tube from the tubesheet, due to axial loading on the tube. Differential pressures from the primary side to the secondary side of the SG impart axial loads into each tube that are reacted at the tube-to-tubesheet interface. Axial tube loading during normal operating conditions can be significant. The peak postulated loading, however, occurs during events involving a depressurization of the secondary side of the SG, such as an FLB or main steamline break. The presence of flaws within an SG tube decreases the load-bearing capability of the affected tube. If a tube becomes sufficiently degraded, these loads could lead to an axial separation of the tube.

The analysis supporting the licensee's proposed modifications to the tube inspection requirements addressed the limiting conditions necessary to maintain adequate structural integrity of the tube-to-tubesheet joint. Specifically, the tube must not experience excessive displacement relative to the tubesheet under bounding loading conditions with appropriate factors of safety considered. Safety factor criteria are derived from the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section III, and are a comparison of applied stresses to the ultimate strength of the tube material. For F*, the most limiting condition for structural integrity is maintaining a margin (safety factor) of 1.4 against the axial loads experienced during faulted conditions.

To justify the structural integrity acceptability of any flaw or combination of flaws below the F* distance, the licensee completed an assessment using analytical calculations and laboratory experiments. This assessment included measurements of the elastic radial preload, due to the hardrolling process, using tube sections rolled into simulated tubesheets (collars). Physical dimensions were measured before and after rolling the tube sections into the collars, and then again after removing the collar. The amount of tube deflection was analyzed to determine the amount of preload radial stress present following the rolling process. The assessment also included calculations of the changes in radial preload during operation due to thermal expansion tightening, differential pressure, and tubesheet bow for normal operating and faulted conditions. The required engagement distance, F*, was then calculated by equating the load-carrying ability of the tube (preload frictional forces) to the applied operating loads. These calculations included a reduction in the load-carrying ability near the ends of a severed tube.

The F* values calculated for current normal operating, normal operating after power uprate, and faulted SG conditions were 1.74 inches, 1.77 inches, and 1.97 inches, respectively. These values were determined using a safety factor of 3 for normal operating conditions and 1.4 for faulted conditions. The most limiting of these values was used to specify the F* length of 1.97 inches in determining the required engagement length of tubing.

In summary, the use of the F* methodology will (1) limit the potential for the growth of flaws in the tubesheet region into the freespan region above the tubesheet, and (2) ensure the tubes will not pull out of the tubesheet. On these bases, the NRC staff has concluded that tubes returned to service using the F* repair criteria will maintain adequate structural integrity.

3.4 Tube Leakage Integrity

In assessing leakage integrity of an SG under postulated accident conditions, the leakage from all sources (i.e., all types of flaws at all locations and all non-leak tight repairs) must be assessed. The combined leakage from all sources is limited by a plant-specific limit that is based primarily on radiological dose consequences. This limit is referred to as the "accident-induced leakage limit." The licensee's approach to addressing leakage from flaws within the tubesheet region considers two regions: (1) the upper portion of the tube that is within 3 inches of the TTS or within 2.22 inches of the BRT, whichever is lower, and (2) the region more than 3 inches below the TTS or 2.22 inches below the BRT, whichever is greater. In general, the licensee assumes there will be no leakage from either region. As discussed below, the NRC staff determined that the leakage from either region will not be significant.

In the top part of the tubesheet, the region in which all tubes with detected flaws must be plugged or repaired, operating experience suggests it is unlikely that through-wall (or near through-wall) flaws will develop given that this area is inspected at least once every 24 effective full-power months. However, the licensee stated that if flaws are detected, they will be evaluated for their effect on the leakage integrity of the SG to confirm this expectation.

For flaws below the region in which all tubes with detected flaws must be plugged or repaired, the licensee's evaluation considered the effects of the hardroll installation, the primary-to-secondary pressure differential, differential thermal expansion, and tubesheet bow on the interference fit between the tube and tubesheet, and compared these effects with the leakage driving force from the primary-to-secondary pressure differential. As discussed above, the evaluation included measurements of the elastic radial preload from the hardrolling process using tube sections rolled into simulated tubesheets (collars). These tests indicated that at 3 inches and greater below the TTS (or 2.22 inches and greater below the BRT), the contact pressure for all tubes in the hot-leg tubesheet region will be higher than the highest anticipated internal pressure of 2650 psi corresponding to an FLB. While the contact pressure calculated for the tubes in the cold-leg tubesheet region did not exceed the FLB internal pressure, the contact pressure was only slightly below the FLB internal pressure, and when considered together with the flow resistance between the tube and the tubesheet, the probability of actual leakage was considered very low, and were any leakage to occur, it would be well below the TS regulatory limits.

Tests to estimate the amount of leakage from a tube with a 360-degree, through-wall circumferential crack within the tubesheet region were performed as part of the evaluation for similar inspection and repair criteria developed for other plants and documented in WCAP-14697. These tests consisted of tubes rolled into steel collars simulating the tubesheet, pressurized to various levels using water at elevated temperature. The tubes had through-wall holes around the entire circumference to simulate the flaw. These simulated flaws were conservative representations of actual cracks. Because of their geometry, actual cracks can be expected to restrict flow more than the simulated (i.e., drilled hole) flaws.

At 619 degrees Fahrenheit and a test pressure of 2650 pounds per second inch (associated with faulted conditions), leakage was detected in three of five specimens with roll expansion lengths of 1 or 2 inches. The maximum leak rate of these three specimens was 1.1×10^{-4} gallons per minute (gpm). The licensee and the NRC staff calculated different average leak rates for these tests (3.1×10^{-5} gpm and 2.5×10^{-5} gpm, respectively). It appears to the NRC staff that the higher calculated average leak rate excludes one of the samples with zero leakage. Nonetheless, this low rate of leakage, coupled with the low likelihood of developing a significant number of through-wall flaws near the TTS (approximately 3 inches below), indicates flaws in this region will not be a significant leakage source relative to the plant's leakage limit. In addition, the shot peening of the roll-expanded tubes should further reduce the likelihood of developing a significant number of severe flaws.

In summary, the NRC staff concluded that the proposed F* distance is acceptable and ensures that the amount of accident-induced leakage from undetected flaws below the F* distance will be negligible compared to the leakage rate assumed in the licensee's accident analyses. The NRC has previously approved similar F* amendments for other plants that assumed negligible accident-induced leakage.

3.5 Reporting Requirements

As part of implementation of the F* methodology, the licensee would add reporting of cold-leg inspection results (as applicable) to the current reporting requirement for hot-leg inspection results in TS 5.6.6.2.4, which require specific information to be submitted to the NRC within 90 days after initial entry into Mode 4 following an outage in which the F* methodology was applied. This report permits the NRC staff to verify the operating experience continues to be conservative relative to the assumptions made in the amendment. As a result, the NRC staff concluded that the proposed changes to the TS reporting requirements are acceptable.

3.6 Summary

The NRC staff finds the licensee's proposed methodology for assessing structural and leakage integrity for flaws in the tubesheet region acceptable. Therefore, the NRC staff concluded that the licensee's proposed repair criteria are acceptable (including inspection and reporting requirements).

4.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The Commission's regulations in 10 CFR 50.92(c) state that the Commission may make a final determination that a proposed license amendment involves no significant hazards considerations if operation of the facility in accordance with the proposed amendment would not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety.

As required by 10 CFR 50.91(a), an evaluation of the issue of no significant hazards consideration is presented below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   No. The proposed change modifies the BVPS-2 TSs to expand the scope of SG tubesheet inspections using the F* inspection methodology to the SG cold-leg tubesheet region based on WCAP-16385-P, Revision 1. Of the various accidents previously evaluated in the

BVPS-2 Updated Final Safety Analysis Report, the proposed change only affects the SG tube rupture (SGTR) event evaluation and the postulated steam line break (SLB) accident evaluation. Loss-of-coolant accident (LOCA) conditions cause a compressive axial load to act on the tube. Therefore, since the LOCA tends to force the tube into the tubesheet rather than pull it out, it is not a factor in this amendment request. Another faulted load consideration is a safe shutdown earthquake (SSE); however, the seismic analysis of Model 51M SGs has shown that axial loading of the tubes is negligible during an SSE.

For the SGTR event, the required structural margins of the steam generator tubes will be maintained by the presence of the tubesheet. Tube rupture is precluded for cracks in the tube expansion region due to the constraint provided by the tubesheet. Therefore, RG 1.121, "Bases for Plugging Degraded PWR [pressurized-water reactor] Steam Generator Tubes," margins against burst are maintained for both normal and postulated accident conditions.

The F* length supplies the necessary resistive force to preclude pullout loads under both normal operating and accident conditions. The contact pressure results from the tube expansion process used during manufacturing and from the differential pressure between the primary and secondary side. The proposed changes do not affect other systems, structures, components or operational features. Therefore, the proposed change results in no significant increase in the probability of the occurrence of an SGTR or SLB accident.

The consequences of an SGTR event are affected by the primary-to-secondary leakage flow during the event. Primary-to-secondary leakage flow through a postulated broken tube is not affected by the proposed change since the tubesheet enhances the tube integrity in the region of the expansion by precluding tube deformation beyond its initial expanded outside diameter. The resistance to both tube rupture and collapse is strengthened by the tubesheet in that region. At normal operating pressures, leakage from primary water stress corrosion cracking (PWSCC) below the F* distance is limited by both the tube-to-tubesheet crevice and the limited crack opening permitted by the tubesheet constraint. Consequently, negligible normal operating leakage is expected from cracks within the tubesheet region.

SLB leakage is limited by leakage flow restrictions resulting from the crack and tube-to-tubesheet contact pressures that provide a restricted leakage path above the indications and also limit the degree of crack face opening compared to free span indications. The total leakage (i. e., the combined leakage for all such tubes) meets the industry performance criterion, plus the combined leakage developed by any other alternate repair criteria, and will be maintained below the maximum allowable SLB leak rate limit, such that off-site doses are maintained less than 10 CFR Part 100 guideline values and the limits evaluated in the BVPS-2 UFSAR.

Therefore, based on the above evaluation, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

No. The proposed changes do not introduce any changes or mechanisms that create the possibility of a new or different kind of accident. Tube bundle integrity will continue to be maintained for all plant conditions upon implementation of the F* methodology to the cold-leg tubesheet region.

The proposed changes do not introduce any new equipment or any change to existing equipment. No new effects on existing equipment are created nor are any new malfunctions introduced.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

No. The proposed changes maintain the required structural margins of the SG tubes for both normal and accident conditions. NRC RG 1.121 is used as the basis in the development of the F* methodology for determining that SG tube integrity considerations are maintained within acceptable limits. Regulatory Guide 1.121 describes a method acceptable to the NRC staff for meeting General Design Criteria 14, 15, 31, and 32. Regulatory Guide 1.121 describes the limiting safe conditions of tube wall degradation beyond which tubes with unacceptable cracking, as established by inservice inspection, should be removed from service or repaired. This RG uses safety factors on loads for tube burst that are consistent with the requirements of Section III of the American Society of Mechanical Engineers Code.

For primarily axially oriented cracking located within the tubesheet, tube burst is precluded due to the presence of the tubesheet. WCAP-16385-P, Revision 1, defines a length, F*, of degradation-free expanded tubing that provides the necessary resistance to tube pullout due to the pressure-induced forces (with applicable safety factors applied). Expansion of the application of the F* criteria to the cold-leg tubesheet region will preclude unacceptable primary-to-secondary leakage during all plant conditions. The methodology for determining leakage provides for large margins between calculated and actual leakage values in the F* criteria.

Plugging of the steam generator tubes reduces the reactor coolant flow margin for core cooling. Expansion of the F* methodology to the cold-leg tubesheet region at BVPS-2 will result in maintaining the margin of flow that may have otherwise been reduced by tube plugging.

Based on the above evaluation, the NRC staff concludes that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff has made a final determination that no significant hazards consideration is involved for the proposed amendments and that the amendment should be issued as allowed by the criteria contained in 10 CFR 50.91.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Pennsylvania State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (76 FR 1648). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: A. Johnson

Date: February 24, 2011

February 24, 2011

Mr. Paul A. Harden
Site Vice President
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Mail Stop A-BV-SEB1
P.O. Box 4, Route 168
Shippingport, PA 15077

SUBJECT: BEAVER VALLEY POWER STATION, UNIT NO. 2 - ISSUANCE OF AMENDMENT REGARDING THE REVISED STEAM GENERATOR INSPECTION SCOPE USING F* INSPECTION METHODOLOGY (TAC NO. ME3498)

Dear Mr. Harden:

The Commission has issued the enclosed Amendment No. 172 to Renewed Facility Operating License No. NPF-73 for the Beaver Valley Power Station, Unit No. 2 (BVPS-2). This amendment consists of changes to the Technical Specifications in response to your application dated February 26, 2010, as supplemented by letters dated November 10, 2010, and January 26, 2011.

The amendment modifies TSs to revise the scope of the steam generator (SG) tube inspections for the portion of the tube in the tubesheet on the cold-leg side of the SG by using the F* methodology.

A copy of the related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,
/ra/
Nadiyah S. Morgan, Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-412

Enclosures:
1. Amendment No. 172 to NPF-73
2. Safety Evaluation

cc w/encls: Distribution via Listserv

ADAMS Accession No.: ML110350162 *Input received. No substantive changes made.

OFFICE	LPLI-1/PM	LPLI-1/LA	CSGB/BC	ITSB/BC	OGC (NLO w/ comment)	LPL1-1/BC
NAME	NMorgan	SLittle	RTaylor	RElliott	LSubin	NSalgado
DATE	2/23/11	2/14/11	1/21/2011*	2/15/11	2/23/11	2/24/11

OFFICIAL RECORD COPY