FPL

April 4, 2020
L-2020-053
10 CFR 50.90
10 CFR 50.91

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington D C 20555-0001

RE: Turkey Point Nuclear Plant, Unit 3
Docket No. 50-250
Renewed Facility Operating License DPR-31
Exigent License Amendment Request 272, One-Time Extension of TS 6.8.4 Steam Generator Inspection Program

Pursuant to 10 CFR Part 50.90 and 10 CFR Part 50.91, Florida Power & Light Company (FPL) hereby requests an exigent amendment to Renewed Facility Operating License DPR-31 for Turkey Point Nuclear Plant Unit 3. The proposed license amendment modifies the Turkey Point Technical Specifications (TS) by extending, on a one-time basis, the requirement to inspect each Steam Generator (SG) at least every other refueling outage, for another eighteen months to the Fall of 2021, when the Unit 3 Cycle 32 refueling outage is currently scheduled. The one-time exigent license amendment is required due to unforeseen issues as a result of the current COVID-19 virus pandemic.

The enclosure to this letter provides FPL's evaluation of the proposed license amendment. The operational assessment and operational experience of the Turkey Point Unit 3 SGs, as described in the enclosure to this letter, demonstrate that the proposed change to the SG inspection schedule is appropriate and does not impact the safe operation of the plant. Attachment 1 to the enclosure provides a mark-up of the existing TS page to show the proposed change. No change is proposed to the current TS Bases as a result of this license amendment request.

FPL has determined that the proposed change does not involve a significant hazards consideration pursuant to 10 CFR 50.92(c), and there are no significant environmental impacts associated with the change. The Turkey Point Onsite Review Group has reviewed the proposed license amendment. In accordance with 10 CFR 50.91(b)(1), a copy of the proposed license amendment is being forwarded to the State designee for the State of Florida.

The proposed exigent license amendment is prompted due to circumstances related to the effects of the COVID-19 virus pandemic. FPL respectfully requests staff review and approval by April 18, 2020, prior to Turkey Point Unit 3 entering MODE 4.

This letter contains no new regulatory commitments.

Should you have any questions regarding this submittal, please contact Mr. Robert Hess, Turkey Point Licensing Manager, at (305) 246-4112.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on April 4, 2020.

Sincerely,

B. Stamp

Brian Stamp
Site Director
Turkey Point Nuclear Plant
Florida Power & Light Company

Enclosure: Evaluation of the Proposed Change

cc: USNRC Regional Administrator, Region II
USNRC Project Manager, Turkey Point Nuclear Plant
USNRC Senior Resident Inspector, Turkey Point Nuclear Plant
Ms. Cindy Becker, Florida Department of Health

EVALUATION OF THE PROPOSED CHANGES

Turkey Point Nuclear Plant Unit 3
License Amendment Request 272
One-Time Extension of TS 6.8.4 Steam Generator Inspection Program

1.0 SUMMARY DESCRIPTION

FPL hereby requests an exigent amendment to Renewed Facility Operating License DPR-31 for Turkey Point Nuclear Plant Unit 3. The proposed license amendment modifies the Turkey Point Units 3 and 4 Technical Specifications (TS) 6.8.4.j, "Steam Generator (SG) Program," by extending, on a one-time basis, the requirement to inspect each Unit 3 Steam Generator at least every other refueling outage, for another eighteen months to the Fall of 2021, when the Unit 3 Cycle 32 refueling outage is currently scheduled. The SG operational assessment and operational experience of the Turkey Point Unit 3 SGs, as described in this enclosure, demonstrate that the proposed change to the SG inspection schedule is appropriate and does not impact the safe operation of the plant. The one-time license amendment is required due to unforeseen issues as a result of the current COVID-19 virus pandemic.

On March 13, 2020, President Donald Trump declared the Coronavirus (COVID-19) pandemic a national emergency. In addition, Florida Governor Ron DeSantis declared a state of emergency on Monday, March 9, 2020 due to the potential spread of COVID-19. In response to these declarations and in accordance with the NextEra Energy's Pandemic Response plan, Florida Power & Light Company (FPL) is reducing the scope of the Unit 3 refueling outage to minimize the threat of the virus to station personnel and ensure the safe operation of Units 3 and 4 during this pandemic. The one-time extension of the SG inspections will reduce the staffing required to support the outage; therefore, reducing the probability of spread of the coronavirus. This request is consistent with measures taken by NRC as reflected in IMC 2515 Appendix E dated March 27, 2020 [ML20079E700].

FPL respectfully requests staff review and approval by April 18, 2020 prior to Turkey Point Unit 3 entering MODE 4.

2.0 DETAILED DESCRIPTION

2.1 Background

Turkey Point Unit 3 is a three-loop Westinghouse designed plant. Unit 3 has three replacement Model 44F SGs that were installed in 1982. Each SG has 3214 tubes. The design of the SG includes Alloy 600 thermally treated tubing, full-depth hydraulically expanded tubesheet joints, and stainless steel support plates with broached hole quatrefoils. Turkey Point Unit 3 completed Cycle 30 and commenced the refueling outage on March 30, 2020. The last SG tube inspection for Unit 3 was completed during the Unit 3 Cycle 29 (TP3-29) refueling outage (RFO) (end of Cycle 28) during the Spring of 2017 with results documented by FPL letter L-2017-146 dated 10/12/2017 (Reference 6.1). The TP3-29 inspection was the first inspection in the 4^{th} Inspection Period (72 effective full power months) and met the requirements of Turkey Point Unit 3 Technical Specification Section 6.8.4.j.d.2.c., NEI 97-06 (Reference 6.2), and its referenced EPRI guidelines.

2.2 Current Requirements

TS 3.4.5, "Steam Generator (SG) Tube Integrity," states that SG tube integrity shall be maintained and that all SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the SG Program.

TS Surveillance Requirement (SR) 4.4.5.1 requires verification of SG tube integrity in accordance with the Steam Generator Program. TS SR 4.4.5.2 requires verification that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the SG Program prior to entering HOT SHUTDOWN following a SG tube inspection.

The SG inspection scope is governed by TS Section 6.8.4.j, "Steam Generator (SG) Program," requirements. Specifically, Item j.d.2 states that "after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below"

TS Section 6.8.4.j Item d.2.a) defines the SG tube inspection requirements after the first refueling outage following SG installation for the next 120 effective full power months – the first inspection period. TS Section 6.8.4.j Item d.2.b) defines the SG tube inspection requirements during the next 96 effective full power months – the second inspection period. TS Section 6.8.4.j Item d.2.c) defines the SG tube inspection requirements for the remaining life of the SGs. TS Section 6.8.4.j, Item d.2.c) states that "During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods." Turkey Point Unit 3 is currently in the 4th Inspection Period.

2.3 Description of the Proposed Change

The proposed change extends on a one-time basis, TS Section 6.8.4.j.d.2 requirements of inspecting each SG at least every other refueling for Unit 3, until the next refueling outage scheduled for Fall 2021 as indicated below:

d. Provisions for SG tube inspections. 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 plugging criteria. The portion of the tube below 18.11 inches from the top of the tubesheet is excluded from inspection. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection 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 tube 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 installation.

2. After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). Add *

*One- time extension for Unit 3 to perform Steam Generator inspections during the Cycle 32 refueling outage in Fall 2021.

In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period beings at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;
b) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and
c) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. Add ** This constitutes the third and subsequent inspection periods.

** One-time extension of the 4th inspection period for Unit 3 until the Cycle 32 refueling outage in Fall 2021.

2.4 Reason for the Proposed Change

The requested extension to the requirement to inspect each Unit 3 SG at least every other refueling outage, for another eighteen months, will allow the Unit 3 SG inspections to be performed during the Unit 3 Cycle 32 refueling outage currently scheduled for the Fall 2021. The requested extension to the requirement to inspect 100% of the tubes of the fourth 72 effective full power months will align the 4th inspection period with the one-time extension to inspect each Unit 3 SG until the Cycle 32 refueling outage currently scheduled for the Fall 2021. The operational assessment and operational experience of the Turkey Point Unit 3 SGs, as described in this enclosure, demonstrate that the proposed change to the SG inspection schedule is appropriate and does not impact the safe operation of the plant. The one-time license amendment is required due to unforeseen issues as a result of the current COVID-19 virus pandemic. The requested one-time extension of the Unit 3 SG inspection schedule will not affect the safe operation of the plant and will significantly reduce the number of employees required during the Unit 3 Cycle 31 refueling outage; therefore, reducing the probability of spread of the coronavirus and ensuring the safe operation of Units 3 and 4 during this pandemic.

2.5 Statement of Exigency

Due to the emergent nature of the coronavirus pandemic, FPL determined that reducing the number of employees required for the Unit 3 Cycle 31 refueling outage and a reduction in outage scope and duration would be necessary to prevent the spread of the coronavirus. This has been a fast-moving process and FPL only recently determined that it would not be prudent to perform the SG inspection during this outage. Once FPL reached this determination, it has endeavored to submit this amendment request as quickly as possible, while keeping in mind the need for the request to be complete, accurate, and with sufficient detail to allow the NRC to perform a review. Because Turkey Point Unit 3 plans to reach Mode 4 by April 18, 2020, it has determined that the need for this LAR is exigent and does not allow for the standard public comment period.

3.0 TECHNICAL EVALUATION

The proposed license amendment modifies the Turkey Point TS by extending, on a one-time basis, the Unit 3 SG inspection until the next refueling outage scheduled for Fall 2021.

3.1 Steam Generator Description

Each of the Turkey Point Unit 3 steam generators (SGs) has 3,214 Alloy 600 thermally-treated (Alloy 600TT) U-bend tubes. The tubes have a nominal outer diameter of 0.875 inches with a 0.050-inch nominal wall thickness. Tubes are identified by row and column designation; there are 45 rows and 92 columns arranged in a square-pitch configuration. Secondary side tube support is provided by 6 quatrefoil broached-hole, horizontal tube support plates (TSPs) along the straight lengths of the tubes, and 2 sets of V-shaped anti-vibration bars (AVBs) along the U-bend regions of the tubes. The TSPs are fabricated from Type 405 stainless steel, and the AVBs are fabricated from square cross-section Alloy 600 bars, which have been chrome-plated. Each SG also has one drill-hole flow distribution baffle (FDB) plate fabricated from stainless steel. Each tube has been hydraulically expanded full-depth into the tubesheet. The tubesheet base metal is clad with Alloy 600 (Inconel) material. The U-bends of rows 1-8 were stress-relieved after bending to reduce residual stresses.

3.2 Background Information

The original Turkey Point Unit 3 SGs were replaced in 1982 due to significant corrosion of the Alloy 600 heat transfer tubes and degradation of the carbon steel tube support plates. The replacement SGs are Westinghouse Model 44F. The tubesheet, tubes, tube support structures, and the SG shell were replaced. The primary channel heads, with the exception of the tubesheets, are the original heads supplied with the original steam generators. The steam separation equipment and feed-ring were upgraded during the replacement outage. The thermal treatment of the tubes was designed to improve the resistance to primary water stress corrosion cracking (PWSCC). Tube holes in the Type 405 stainless steel TSPs are quatrefoil designs to minimize the areas of contact between the tubes and the inside surfaces of the broached holes.

The SGs at Turkey Point Unit 3 have undergone a pre-service inspection (PSI) and seventeen in-service inspections (ISI) since replacement. Wear at tube support structures and from foreign objects has been observed through the end of the last tube inspection. No other degradation mechanisms have been observed. No tubes have ever been plugged in the Unit 3 SGs for corrosion or cracking mechanisms. Since installation, a total of 50 tubes have been plugged in SG-3A, 83 tubes plugged in SG-3B, and 63 tubes plugged in SG-3C. Over one-half of the total tubes plugged belonged to 1 of 2 categories: 1) tubes plugged at PSI or at the factory, and 2) tubes identified as having minor geometric variations associated with the tube-to-tubesheet joint fabrication process, but were not due to degradation. (The second category occurred during an early application of the +Point™ probe at the EOC 17 inspection in Spring 2000 (Reference 6.4). Note: outage designators TP3-29 or PT3-29 refer to the outage at the EOC 28.

3.3 Steam Generator Inspection Plan

The Turkey Point Unit 3 Steam Generator Program (TS 6.8.4.j) reflects the adoption of “Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection” (TSTF-510 Revision 2) for Westinghouse-designed plants (NUREG-1431) with Alloy 600TT tubing (Reference 6.5). The sample sizes and frequencies for eddy-current (ECT) inspections are such that they meet the requirements of the TS. This is shown in the

Table below for Turkey Point Unit 3 for the (current) 4th inspection period. The inspection scope shown for EOC 30 reflects what was planned leading up to the outage:

			4th Inspection Period (72 EFPM)				
		Cycle #	EOC 27	EOC 28	EOC 29	EOC 30	
		RFO #	PT3-28	PT3-29	PT3-30	PT3-31	
		Cycle EFPH:	6,687	11,120	12,164	12,019	
		Cycle EFPY:	0.76	1.27	1.39	1.37	
		Period EFPM:	9.16	24.39	41.06	57.52	**72.00**
		SG Cumulative EFPY:	26.13	27.40	28.79	30.16	
Exam Scope	Extent	ECT probe	Exam sample size				
Full-length exams	rows 3+	bobbin		100%		100%	
HL/CL straight sections	rows 1, 2	bobbin		100%		100%	
HL tubesheet	01H to TEH	Array		50%		50%	
Bulges/Over-expansion	HL tubesheet	Array	skip	50%	skip	50%	
Low-row U-bends	rows 1, 2	+Point™		50%		50%	
Dings/Dents >5V	HL freespan, U-bend	+Point™		50%		50%	
Dings/Dents	HL tube supports	+Point™		50%		50%	
High stress tubes	HL tubesheet	+Point™		100%		100%	
High stress tubes	HL/top CL TSPs	+Point™		25%		75%	
HL/CL Periphery Tubes	TTS, 3 outer rows	Array		100%		100%	

3.4 Technical Analysis

3.4.1 Recent Operational Experience Summary

Mechanical wear at tube support structures (AVB, TSP, FDB) has been reported for the EOC 28 SG inspection. Some of these indications were also associated with possible loose parts (PLPs). Indications at TSPs were associated with the land contacts or at the edges (upper or lower). Most of the indications were previously observed; some were newly-reported. Attachments 2-4 of the EOC 28 SG Tube Inspection Report (Reference 6.1) documents the list of indications. The Table below summarizes the inspection results:

EOC 28 Inspection Summary - Total indication count / Newly detected / Plugged

Degradation Location	SG-3A	SG-3B	SG-3C	Total
AVB	25 / 1 / 1	40 / 2 / 0	147 / 6 / 0	212 / 9 / 1
TSP (land)	2 / 0 / 0	4 / 0 / 0	8 / 0 / 0	14 / 0 / 0
TSP (edge)	8 / 7 / 1	2 / 2 / 1	9 / 6 / 0	19 / 15 / 2
TSP (edge/PLP)	0 / 0 / 0	1 / 1 / 1	1 / 1 / 1	2 / 2 / 2
FDB	0 / 0 / 0	2 / 0 / 0	0 / 0 / 0	2 / 0 / 0
Tube Obstruction	0 / 0 / 0	1 / 0 / 1	0 / 0 / 0	1 / 0 / 1
Total:	35 / 8 / 2	50 / 5 / 3	165 / 13 / 1	250 / 26 / 6

For the tubes that were plugged, Table 3 of Reference 6.1 has additional details on the reason for plugging.

The results of sludge lancing, secondary-side FOSAR and upper internals inspection are detailed in section A of Reference 6.1. Visual inspection of the upper bundle region of one SG is typically completed during secondary-side inspections. There has been no significant buildup of deposits in this area. In addition, the SGs have not experienced water level instability during operation.

Failure of a SG feed water pump strainer in May 2013, introduced fragments into the feed water train. All discovered loose parts were removed shortly after the event. At the last 2 consecutive SG secondary-side inspections (EOC 26, EOC 28), no significant parts resulting from the failed strainer were found during in-bundle FOSAR in the SGs. An evaluation is documented for any postulated loose part which may have not been identified; additional information is available in section 3.4.3.

There has been no detectable primary-to-secondary leakage since the last inspection. No significant Chemistry transients occurred at Turkey Point Unit 3 since the last SG inspection at EOC 28. Poly-acrylic acid injection was implemented 18 months ago to improve iron removal from the SGs.

3.4.2 Previous Inspection Condition Monitoring

During the EOC 28 (PT3-29) outage in Spring 2017, the SG tubes were inspected in accordance with TS 6.8.4.j (Steam Generator Program), and condition monitoring was performed as required (TS 6.8.4.j.a). A SG Tube Inspection Report was submitted to NRC (Reference 6.1) per TS 6.9.1.8 based on this inspection.

Inspection Strategy: The scope of inspections performed is detailed in section A of Reference 6.1 as well as the extent of each exam technique used. Degradation mechanisms found are outlined in section B of the Report, and repeated here for convenience:

- Wear at anti-vibration bars (AVBs)
- Wear at tube support plates (TSPs)
- Wear at flow distribution baffle plates (FDBs)
- Foreign object wear at TSP edges

Table 2 of Reference 6.1 documents the ECT inspection techniques used for detection and sizing of each existing and potential damage mechanism. The through-wall depth of each indication is listed in the Attachments. All detected indications met condition monitoring (CM) with large margins when compared to the pre-outage screening charts of allowable depths vs. length of degradation that meet the SIPC margin requirement for Unit 3 (PTN3).

Analysis of Profiled Indications: PTN routinely performs profile analysis for the purpose of tracking the shape of wear scars, especially new indications, and flaws that exceed the TS limit. This information is used to track the wear degradation for updating the CM screening charts for future inspections. All profiles obtained during the PT3-29 inspection were discretionary in nature and were not required for CM. Before the inspection, conservative special interest criteria are developed and applied to further screen these indications with +Point™ line-by-line sizing and an accompanying profile analysis. A total of 22 profiles were produced: 8 in SG-3A, 4 in SG-3B and 10 in SG-3C. Two profiles were evaluated for TSP edge wear and AVB wear. The profile for the deepest bobbin indication for TSP wear in SG-3A (43% TW in R25 C19 at 05C) was evaluated with OPCON 3.03 ProfilerAx software module for tube integrity by direct calculation of burst pressure by the structural minimum method (Reference 6.6). The results for this profile evaluation gave a minimum 95-50 burst pressure of 6,890 psi, compared to a 3xNOPD value of 4,542 psi (Reference 6.3). The profile for the deepest bobbin indication for AVB wear in SG-3A (R37 C47 at AV3) was evaluated in a similar manner. The results for this profile evaluation gave a minimum 95-50 burst pressure of 6,070 psi. None of the wear indications challenged the CM limits, and no indications required in-situ pressure testing.

Therefore, the minimum burst pressures for these two indications exceed the SIPC margin requirement of 3xNOPD. The profile evaluations confirm that CM was satisfied by direct burst pressure calculation for the two limiting indications.

Identification and monitoring of High Stress Tubes:
The initial screening for “signature tubes” in the Turkey Point Unit 3 steam generators was performed prior to the EOC 19 outage. Screening of short-row tubes (rows 1-8) for PTN3 revealed no signature tubes. The long-row tubes screening (rows 9-45) for PTN3 used the Westinghouse screening technique developed at Seabrook. Eighteen (18) long-row tubes exhibiting a U-bend offset of <2 volts were flagged with the LVU (low voltage U-bend) code. The 18 signature tubes were then reviewed during the EOC 19 outage for precursors of degradation and none were found. Subsequently, the new minus 2 sigma (-2σ) criteria in a 2004 EPRI SGMP Information Letter (Reference 6.7) were also used to re-evaluate the data (in EOC 22 in 2007), which produced a list of 41 additional signature tubes for a combined total of 59 tubes. Eddy-current (ECT) data from the bobbin examination were also analyzed for these signature tubes during the EOC 24 inspection. For the EOC-28 SG tube inspection in Spring 2017, a revised methodology was used to re-evaluate the bobbin voltage offset for PTN3 on a row-by-row basis, resulting in an additional 18 tubes being identified as signature tubes. Based on the revised methodology, a total of 77 signature tubes have been identified for PTN3; 22 in SG-A, 38 in SG-B, 17 in SG-C.

The screening review of the bobbin data to identify tubes that may have higher residual stress levels relative to the remaining tube population was performed and documented for PTN3 (Reference 6.8). Based on OE at other plants with A600TT tubing, these tubes may be more susceptible to an earlier onset of stress corrosion cracking; therefore, identification and subsequent monitoring of these tubes was recommended by the industry. Based on more recent guidance from the SG OEM, for the EOC-28 SG tube inspection in Spring 2017, additional sampling of the high stress tubes using the +Point™ probe (in addition to the bobbin coil screening technique) was performed for the PTN3 SGs. The inspection strategy entailed collecting and analyzing the +Point™ data of eight tubes with the largest offset voltages at every SG inspection. In addition, a sample of the remaining high stress tubes is tested at each inspection. The scope of the +Point™ inspections of high stress tubes is at all hotleg TSPs (including the FDB) and the top TSP on the cold-leg (CL) side. In this manner, the inspection approach is to test all high stress tubes at HL and top CL supports with the +Point™ probe at least once in each inspection period. Since a 25% of the tube support locations were tested during EOC 28, the remaining 75% are scheduled to be inspected at the next SG inspection. Apart from the scope described, within the tubesheet, 100% of high stress tubes are tested with the +Point™ probe from the HL TTS+3 inches down to the HL tube-end at each inspection. In addition to the above, the bobbin probe data for all 77 high stress tubes are subjected to a special review by the Lead Analyst or designee during every inspection.

The +Point™ data for all of the locations discussed above are monitored for any indications that may be indicative of corrosion-related degradation. The bobbin probe data review consists of the analyst looking specifically for precursor signals that could be an indication of the onset of stress corrosion cracking due to the potential elevated high stress in those tubes. This review was documented by having the Lead analyst add an LVU (low voltage u-bend) indication to the database once the review was completed. Combining the review of high stress tube data from both the +Point™ (at select locations) and bobbin probes (the entire tube), provides a defense in-depth approach to identifying an indication of corrosion degradation in these tubes. In EOC 28, this review revealed no precursor signals that could be indicative of the onset of corrosion-related degradation.

Previous OA Benchmarking: A comparison of the worst case tube predictions for EOC 28 to the actual detected degradation depths is given in the table below:

Mechanism	Previous OA (EOC 26) Predictions[1]	max. depth[2] at EOC 28 (95-50)
Anti-Vibration Bar Wear	54.3% TW	46.0% TW
Wear at TSP Lands	47.6% TW	30.7% TW
Wear at TSP Edges	56.5% TW	46.3% TW
Wear at Flow Baffle Plate	48.5% TW	25.7% TW

Note:
1. Adjusted to the actual 2-cycle operating period of 2.689 EFPY. OA predicted depths include sizing error at 95-50 uncertainty level.
2. Maximum depths are estimated actual depths for the inspection technique

From the above comparison, the previous OA worst case projected depths bound the observed maximum depths at EOC 28. The number of newly detected indications for EOC 28 is also similar to the previous inspection at EOC 26. Therefore, the OA methods and input assumptions are confirmed and continue to remain acceptable for future OAs for PTN3.

3.4.3 **Operational Assessment During Additional Operating Cycle**:

EXISTING DEGRADATION MECHANISMS:
The technical justification for deferring the PT3-31 SG tube examination by one operating cycle is based on a revised operational assessment (OA) performed in accordance with EPRI SGMP Steam Generator Integrity Assessment Guidelines (Reference 6.6). The revised OA supplements the current EOC 28 OA for the March 2017 outage and evaluates the predicted condition of the SGs after three cycles of operation (Cycles 29, 30, and 31). The results of the revised OA fully support the skipping of the EOC 30 SG inspections where, for the existing and potential degradation mechanisms,

1) structural integrity performance criterion (SIPC) margin requirement of three times normal operating pressure (3xNOPD) on tube burst will be satisfied at EOC 31 for existing and potential degradation, and
2) accident-induced leakage performance criteria (AILPC) for the limiting accident condition will be met for Cycle 31.

Further, the Turkey Point SG Management Program complies with the guidance and recommendations of EPRI SGMP for conducting tube examinations, primary-to-secondary leakage monitoring, performing tube integrity assessment for condition monitoring and operational conditions, conducting in-situ pressure testing, when required, and water chemistry controls. PTN3 has implemented current industry guidelines with respect to primary and secondary water chemistry. No significant chemistry excursions have occurred in PTN3 since the last tube examination in March 2017.

No increased SG tube degradation is expected in the extended operating period as supported by the current degradation assessment (DA) and revised OA. No operational leakage has been reported in the PTN3 SGs. Active monitoring for primary-to-secondary leakage provides assurance that proper plant response will occur in the event primary-to-secondary leakage were to develop during the proposed operating period. The details of the OA are described below:

Prior examination at EOC 28 (March 2017) identified wear at anti-vibration bar (AVB) locations, wear at tube support plate (TSP) tube intersections, and wear at flow distribution baffle plates (FDB) as the only existing degradation modes. There was no corrosion degradation observed at EOC 28 or in any prior examinations. Supplemental tube exams have been performed specifically looking for corrosion degradations (SCC, IGA, pitting, etc.) starting at EOC 13 (April 1994). As of EOC 28, PTN3 had successfully operated approximately 27.4 cumulative EFPYs without cracking. (It should be noted that the most recent examinations at Turkey Point (PTN) Unit 4 at EOC 30, after 28.5 cumulative EFPYs, did not identify any new degradation mechanisms involving corrosion degradation.)

The OA evaluation for PTN-3 was re-evaluated for the existing mechanisms including foreign objects known or postulated to be remaining in the SG secondary side using the same bounding deterministic methods (of Reference 6.6) found that extending the inspection interval by one cycle (approximately 18 months), would not have a significant impact on maintaining tube integrity through to October 2021. Therefore, given the examination scope implemented at EOC 28, all structural and accident leakage performance criteria in NEI 97-06 are predicted to be met through the end of Cycle 31 for the existing degradation.

<u>Methodology, Inputs and Assumptions</u>:
A deterministic OA was completed at EOC 28 for a 2-cycle operating period based on predicted burst pressures and accident-induced leakage, site-specific structural limits, and degradation growth rates through to EOC 30. This OA is re-evaluated for a 3-cycle operating period skipping the tube examination at EOC 30. The OA considered the scope of the examination, potential for increased growth rates, and the potential for increased numbers of indications at subsequent examinations.

The existing mechanisms are wear degradation due to tube contact points at AVBs, TSP intersections, and at FDB locations. Wear degradation from known foreign objects in each SG are also evaluated for a 3-cycle operating period. The OA for each degradation mechanism evaluated a run-time plan for the future cycles of operation. The deterministic calculations for AVB wear, wear at TSPs, and wear at FDB is based on the guidance contained in the EPRI SGMP Integrity Assessment Guidelines (Reference 6.6). Plug (or repair) on NDE sizing strategy is used in the OA of the existing mechanisms. The basic analysis steps for each degradation mechanism are:

1. Identify the largest flaw indication which could potentially remain in service at BOC.
2. Apply NDE bounding uncertainty to the largest flaw potentially remaining in service at BOC.
3. Calculate the projected largest flaw at EOC for each scheduled outage by applying the upper 95th percentile growth rate for the next operating period to the largest flaw at BOC.
4. Compare the projected largest flaw size at future EOC inspections to the structural limit size.
5. Compare the projected largest flaw size at future EOC inspections to leakage size.

A successful deterministic OA for 3-cycles must demonstrate that the performance criteria for tube integrity (burst and leakage) will be satisfied at the acceptance probability of occurrence level of 95-50 for all input conditions. Compliance with the structural performance criterion is indicated when:

$$d_{EOC} < d_{SL} \qquad (3\text{-}1)$$

where d_{EOC} is the limiting defect depth at the next tube examination, and d_{SL} is the structural limit. The projected limiting defect for wear is determined from

$$d_{EOC} = d_{DET} + WR(t_{INSP}) \qquad (3\text{-}2)$$

where d_{DET} is the actual defect size that can be reliably detected by the inspection technique, WR is the bounding wear rate, and t_{INSP} is the projected cycle length until the next examination. For plug (or repair) on NDE sizing, the BOC defect size is based on distribution of measured or observed sizes, the projected limiting defect must consider NDE measurement uncertainty:

$$d_{EOC} = d_{NDE} + d_{ERR} + WR(t_{INSP}) \qquad (3\text{-}3)$$

where d_{NDE} is the measured size, and d_{ERR} is the total measurement error at the upper 95% bound.

Verification by benchmarking predictions with observations as recommended by Reference 6.6. This process was performed to confirm that analysis input and assumptions regarding detection and progression of the existing degradation mechanism are correct. Benchmarking of the predicted worst-case depths from the prior EOC 26 OA with the NDE results at EOC 28 tube examinations demonstrated that the OA model calculation results bound the largest detected indications for all degradation mechanisms. Therefore, this confirms the prior OA methods and assumptions for existing mechanisms are conservative, and therefore appropriate for assessing a 3-cycle operating period.

<u>Wear at Anti-Vibration Bars</u>: As documented in Reference 6.1, the EOC 28 examination for AVB wear consisted of full-length bobbin probe examination of 100% of the active tubes in Rows 3 and higher, and 50% examination of the U-bend regions in Rows 1 and 2 by +Point™. Wear indications were sized, based on an EPRI qualified examination technique (ETSS 96004.1). The largest indication allowed to remain in-service at EOC 28 was 36% TW. Historical tube wear data for AVB supports for 2010 through 2017 show that AVB wear rates are low with a large percentage of indications showing no growth. There is no significant impact of the power uprate (EPU) implemented in 2012. The general trend is for both the average and upper 95th percentile wear rates to attenuate over time.

The applied wear rate for AVB wear is 3.3 %TW per EFPY and represents an upper 95th percentile bound as described in the original OA report. The projected depth is less than the 3xNOPD EOC Structural Limit of 64.9% TW after a 3-cycle operating period to EOC 31 (Reference 6.3). Therefore, the structural performance criteria of NEI 97-06 will be satisfied. The cumulative projected accident leakage will be negligible over the next operational period based on the projected limiting depth sizes for this mechanism.

<u>Wear at Tube Support Plates</u>: For wear indications at TSP locations occurring at the broached-hole lands and at outside surface edges, the projected wear rate for use in the deterministic OA was established from current and past inspection data. The OA structural limit for comparing with the projected limiting wear depth is calculated as 66.6% TW from the geometric profile model for wear at the lands of the broach holes or TSP edges. The largest wear depth from the EOC 28 examination is 14% TW and 19% TW for wear at the lands and the edges, respectively. Depth sizing for TSP wear uses +Point™ probe (ETSS 96910.1). The results from the OA evaluation for 3-cycles of operation are shown in Figures 5-3 and 5-4 of Reference 6.3. The applied wear rates are bounding based on the evaluation described in the original OA report. The projected depths for both TSP locations are less than the 3xNOPD EOC Structural Limits after a 3-cycle operating period to EOC 31. Therefore, the structural performance criteria of NEI 97-06 will be satisfied. The cumulative leakage rate for TSP wear indications was determined to be negligible based on the upper 95% one-sided tolerance limit on peak depth.

Wear at Flow Distribution Baffle Plates: The EOC 28 examination, which consisted of full-length bobbin probe examination of 100% of the active tubes, detected wear/volumetric indications at flow distribution baffle plates. The indications were sized with +Point™ probe (ETSS 96910.1). The EOC Structural Limit for comparing with the projected limiting wear depth at EOC has been established at 71.4% TW. The maximum NDE depth of the indication returned to service is 9% TW. Due to limited inspection data, a bounding wear rate is estimated from the past inspections for Turkey Point and other industry information. For the previous PTN OAs, with little or no growth observed since EOC 26, the upper 95th percentile wear rate was conservatively defined as 6.5%TW per EFPY consistent with TSP wear rates. The results of the depth projection over three cycles are bounded by the EOC structural limit. Therefore, the structural performance criteria of NEI 97-06 will be satisfied at EOC 31. The cumulative projected accident leakage will be negligible over the next operational period based on the projected limiting depth sizes for this mechanism.

The average values and upper 95th percentile wear rates (WR) are summarized in the Table below:

Location of Wear Mechanism	Average WR (%TW/ EFPY)	95-50 WR (%TW/ EFPY)	Maximum Limit (%TW/ EFPY)
AVBs	1.5	3.3	10
TSP at Lands	3.67	6.5	12
TSP at Edges	-	6.5*	-
Flow Baffles	1.92	6.5	12

*Note: From most recent inspection at Turkey Point Unit 4 at EOC 30. Data too limited to establish a full distribution.

Foreign Object Wear evaluation:
Secondary side foreign objects found in the steam generators and PLP locations identified by ECT at EOC 28 were evaluated. All newly discovered foreign objects have been removed including all discovered loose parts shortly after the feed pump (SGFP) strainer failure, which occurred in May 2013. There were no significant parts resulting from the SGFP strainer found at EOC 26 or EOC 28. The potential of having additional loose parts enter the tube bundle has also been evaluated.

Although it is not likely to have any strainer failure debris remaining in the SGs after multiple secondary-side inspections (SSI), any possible foreign objects remaining in the feedwater train (from the SGFP suction strainer failure) that have the potential to migrate to the SGs have been evaluated; the more likely debris arising from strainer failure were considered. The most limiting wear time from this assessment is 3.68 years, and is based on wear time projections to the Technical Specification repair limit of 40%TW, which is generally much less than an appropriate structural limit to meet the SIPC margin requirements. Assuming a wear scar from a foreign object that is a 1-inch-long of uniform depth (flat shape), the CM structural limit is 53% TW. By scaling the wear time for the postulated loose strainer part, the adjusted wear time becomes 4.88 EFPY. All known historical foreign objects that still remain in the generators and are actively tracked have been evaluated. The limiting object has been classified as metallic slag and resides in SG-3B. The limiting operating time for this loose part is 4.92 years, which is longer that the extended operating interval of 4.26 EFPY for Cycles 29 through and 31. Therefore, any potential future wear caused from historical foreign objects will be bounded for the 3-cycle interval between ECT inspections.

Summary of OA for Existing Mechanisms: The deterministic OA consisted of a comparative evaluation of the projected limiting indication size with the structural limit for each mode of degradation. The maximum calculated operating interval for each existing degradation mode is summarized in the Table below. Based on a projected 3-cycle operating interval to EOC 31 of 4.26 EFPY (Reference 6.3), there is margin to the tube integrity performance criteria for each existing degradation mechanism.

Degradation Mode	Allowable Interval (EFPY)	Margin on 3-cycle operating period
AVB Wear	5.72	1.46
TSP Wear at Lands	5.70	1.44
TSP Wear at Edges(1)	7.16	2.90
FDB Wear	7.04	2.78
Loose Part Wear(2)	4.88	0.62
Loose Part Wear(3)	4.92	0.66

Notes:
1) This allowable interval is based on the most recent inspection results on wear rates from PTN4 in March 2019.
2) Re-evaluated limiting foreign object from strainer debris and postulated to exist in a limiting location in the steam generators.
3) The operating period for the limiting known/tracked loose part in SG-3B.

Accident-induced leakage for the existing degradation mechanisms is projected to be negligible for 3 operating cycles based on the peak depths projected to EOC 31.

In summary, the updated EOC 28 OA supports the operation through the extended operating period (Cycles 29 through 31). The performance criteria of NEI 97-06 will be satisfied for the three-cycle inspection interval.

POTENTIAL DEGRADATION MECHANISMS:
As documented in the EOC 28 SG degradation assessment (DA), there are several corrosion-related degradation mechanisms that are classified as potential for A600TT tube material. These mechanisms involve forms of stress corrosion cracking (SCC) on the primary (ID) or secondary-side (OD), oriented either axial or circumferential to the tube axis, and occurring at different locations in the tube bundle. For PTN3, these potential mechanisms are,

1. Axial and circumferential ODSCC at the top-of-tubesheet (TTS)
2. Axial and circumferential PWSCC at the TTS (generally bounded by ODSCC analyses)
3. Axial ODSCC at TSP intersections on non-high residual stress tubes
4. Axial ODSCC at TSP intersections on known high residual stress tubes
5. Axial ODSCC at tube dings and dents
6. Axial ODSCC in freespans
7. PWSCC in small radius U-bends

The more limiting mechanisms are the first five in the above list. These mechanisms are existing in other A600TT plants. The last two in the list, axial ODSCC in freespans and PWSCC in small radius U-bends, have not occurred in operating plants. These mechanisms are not formally evaluated but considered to be bounded by axial ODSCC at TSPs.

Methodology, Inputs and Assumptions:
The potential mechanisms have been proactively monitored by performing additional qualified eddy-current test (ECT) examinations in past outages. To date, PTN3 has not experienced any corrosion degradation within the tube bundle, except at the tube-ends which is outside of the defined pressure boundary for the tubesheet established by the H* Alternate Repair Criteria for PTN3 (Reference 6.9). In the revised OA, the above potential mechanisms were all postulated to exist following the last inspection. These mechanisms were each evaluated by performing full-bundle probabilistic analyses to calculate the probability of tube burst and leakage potential in accordance with Section 8.3 in the EPRI SGMP Integrity Assessment Guidelines (Reference 6.6). The probabilistic model included the important input distributions for material strength properties for the tubing, probability of detection for the ECT technique, a lognormal crack growth rate model appropriate for each mechanism at T_{hot}, and the use of a Weibull initiation function predicting when SCC flaws have developed over time. The overall numerical model is discussed in the revised OA (Reference 6.3).

The following conservative conditions were assumed at the start of the analysis:

1) All potential mechanisms are assumed to be existing and evaluated in the OA.
2) It is assumed that prior to the most recent tube examination, SCC had initiated and was missed (not detected) by ECT during the inspection. This assumption will create a population of undetected flaws that will exist at the start of the cycle following the inspection.
3) The default crack growth rates were conservatively used in the OA followed EPRI SGMP Integrity Assessment Guideline recommendations for A600TT tubing (Reference 6.6).
4) For mechanisms that were sampled at the last inspection, the tube population was divided into two grouping per the implemented sampling plan (inspected and non-inspected) in accordance with Section 8.6 of Reference 6.6. The probability of burst and leakage assessment was individually computed for each partially inspected group and later numerically combined to give the total probabilities for the mechanism.

   In support of the probabilistic OA for the potential mechanism, a lead-plant evaluation was performed where the operating history of PTN3 was compared with those plants that have experienced SCC to estimate equivalent initiation times for each mechanism. This information was primarily used to establish when initiation at PTN3 would have occurred, or will occur, and to help to define the range of Weibull parameters appropriate for PTN3 for the OA.

Summary of OA for Potential Mechanisms: An OA for the potential mechanisms identified above for PTN3 SG tubing has been completed to support deferring the EOC 30 inspections by one operating cycle. The OA evaluated all potential corrosion degradation mechanisms under the assumption that they are active following the last inspection at EOC 28. The results for probability of burst, leakage, calculated leak rates under the postulated limiting accident conditions are summarized in Table 6-1 of the revised OA (Reference 6.3). The limiting potential mechanism is axial ODSCC at TSPs, which includes all of the tubes with high residual stress in the limiting SG. The number of at-risk tube locations included all tube intersections on the hot-leg side (~275 potential crack initiation sites). This large number of possible cracking locations is sufficiently large to accommodate multiple cracks in a single tube as well as the possibility that if any tubes in the bundle that are “high residual stress” were missed during the ECT screening (i.e., signature and 2σ classification), they would be accounted for in the OA evaluation.

The calculated probability of burst for all evaluated mechanisms satisfy the SIPC margin requirement of 3xNOPD for three cycle operating period through to EOC 31. The cumulative accident-induced leakage is determined by summing the projected leak rates at EOC 31. It would not be credible to assume that all potential mechanisms would be active in one operating period. Assuming three limiting mechanisms become active in one SG (i.e., axial ODSCC at TSPs, circumferential ODSCC at TTS, and axial ODSCC at dings/dents), the cumulative leak rate is determined to be 0.11 gpm. This leakage value is less than the AILPC leak limit of 0.2 gpm for any one SG. Therefore, there is reasonable assurance that both tube structural integrity and leakage performance meet the requirements of NEI 97-06 and the PTN3 Technical Specifications, even under the conservative assumptions described above.

3.4.4 **Mitigating Strategies**

During the proposed one-time 18-month extension of the Unit 3 SG inspection, TS 3.4.6.2, Reactor Coolant System Operational Leakage will continue to provide the same level of protection against SG tube leakage. TS 3.4.6.2 states that RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day. In addition, the Unit 3 SGs will continue to comply with TS 6.8.4.j.b, “Performance criteria for SG tube integrity.” Procedural direction exists to monitor operational leakage and proceed to address rapid changes in operational leakage with reduction in reactor power prior to reaching the 150 gallons per day TS limit.

3.5 **Conclusions**

The proposed license amendment to extend the performance of the SG inspection for another 18 months on a one-time basis is reasonable and does not impact the safe operation of the plant. The operational assessment and operational experience of the Turkey Point Unit 3 steam generators, as described in this enclosure, demonstrate that the proposed change to the SG inspection schedule is appropriate and does not impact the safe operation of the plant.

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

- 10 CFR 50.36(c)(2)(i) states that Limiting Conditions for Operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

- 1967 NRC Proposed General Design Criteria (GDC) 1, 2, 5, 9, 16, 33, 34, 36 and 40 define requirements for the reactor coolant pressure boundary (RCPB) with respect to structural integrity and leakage integrity.

- 1967 NRC Proposed GDC 70 (GDC 19 of 10 CFR 50, Appendix A), defines requirements for the control room and for the radiation protection of the operators working within it. Accidents involving the leakage or burst of SG tubing comprise a challenge to the habitability of the control room.

- 10 CFR 50, Appendix B, establishes quality assurance requirements for the design, construction, and operation of safety related components. The pertinent requirements of this appendix apply to all activities affecting the safety related functions of these components. These requirements are described in Criteria IX, XI, and XVI of Appendix B and include control of special processes, inspection, testing, and corrective action

- 10 CFR 100, Reactor Site Criteria, establishes reactor site criteria, with respect to the risk of public exposure to the release of radioactive fission products. Accidents involving leakage or tube burst of SG tubing may comprise a challenge to containment and therefore involve an increased risk of radioactive release.

- Under 10 CFR 50.65, the Maintenance Rule, licensees classify SGs as risk significant components because they are relied upon to remain functional during and after design basis events. SGs are to be monitored under 10 CFR 50.65(a)(2) against industry established performance criteria. Meeting the performance criteria of NEI 97-06, Revision 3, and TS 6.8.4.j.b provides reasonable assurance that the SG tubing remains capable of fulfilling its specific safety function of maintaining the reactor coolant pressure boundary. The SG tube performance criteria in NEI 97-06, Revision 3, and TS 6.8.4.j.b are:

    1) Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown), all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.
    2) Accident induced leakage performance criterion: The primary-to-secondary accident induced leakage rate for any design basis accident, other than SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 0.60 gpm total through all SGs and 0.20 gpm through any one SG at room temperature conditions.
    3) The operational leakage performance criterion is specified in LCO 3.4.6.2, “Reactor Coolant System Operational Leakage.”

The proposed license amendment complies with the requirements of 10 CFR 50.36(c)(2)(i) and does not alter the manner in which the Turkey Point will be operated and maintained consistent with 1967 NRC Proposed General Design Criteria (GDC) 1, 2, 5, 9, 16, 33, 34, 36 and 40, 10 CFR 100, and 10 CFR 50.65. All applicable regulatory requirements will continue to be satisfied as a result of the proposed license amendment.

4.2 No Significant Hazards Consideration

The proposed license amendment modifies the Turkey Point Units 3 and 4 Technical Specifications (TS) by extending, on a one-time basis, the performance of the Unit 3 SG inspection until the next refueling outage scheduled for Fall 2021. As required by 10 CFR 50.91(a), FPL has evaluated the proposed change using the criteria in 10 CFR 50.92 and has determined that the proposed change does not involve a significant hazards consideration. An analysis of the issue of no significant hazards consideration is presented below:

(1) Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

The proposed license amendment modifies the Turkey Point TS by extending the Unit 3 Steam Generator inspection by one cycle until the Unit 3 refueling outage scheduled for Fall 2021. The SG tubes continue to meet the SG Program performance criteria and remain bounded by the plant's accident analyses. The operational assessment reanalysis demonstrates that the SG tubes meet the SG Program performance criteria throughout the 18-month one-time extension of the SG inspection.

Therefore, facility operation in accordance with the proposed changes would not involve a significant increase in the probability or consequences of an accident previously evaluated.

(2) Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No

The proposed license amendment modifies the Turkey Point TS by allowing a one-time extension of the Unit 3 Steam Generator inspection by one cycle until the Unit 3 refueling outage scheduled for Fall 2021. The proposed change does not alter the design function or operation of the SGs or the ability of an SG to perform their design function. The SG tubes continue to meet the SG Program performance criteria. The proposed change does not create the possibility of a new or different kind of accident due to credible new failure mechanisms, malfunctions, or accident initiators that are not considered in the design and licensing bases.

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 amendment involve a significant reduction in a margin of safety?

Response: No

The proposed license amendment modifies the Turkey Point TS by allowing a one-time extension of the Unit 3 Steam Generator inspection by one cycle until the Unit 3 refueling outage scheduled for Fall 2021. Extending the inspection schedule does not involve changes to any limit on accident consequences specified in the Turkey Point licensing bases or applicable regulations, does not modify how accidents are mitigated and does not involve a change in a methodology.

Therefore, operation of the facility in accordance with the proposed change will not involve a significant reduction in the margin of safety.

Based upon the above analysis, FPL concludes that the proposed license amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92, “Issuance of Amendment,” and accordingly, a finding of “no significant hazards consideration” is justified.

4.3 Conclusion

In conclusion, based on the considerations discussed above, (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.

5.0 ENVIRONMENTAL CONSIDERATION

The proposed amendment modifies a regulatory requirement with respect to the installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or changes an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

6.1 Attachment 1 to L-2017-146, Steam Generator Tube Inspection Report,” October 12, 2017 (ML17325A998)

6.2 NEI 97-06 Revision 3, “Steam Generator Program Guidelines, January 2011.

6.3 Intertek Report (proprietary) AIM-200310774-2Q-1, Operational Assessment for Deferring the TP3-31 Steam Generator Tube Examinations for Turkey Point Unit 3 to the TP3-32 Outage in October 2021, April 2020.

6.4 Turkey Point Unit 3, Steam Generator Tube Plugging Inservice Inspection 12-month Special Report, (ADAMS Accession No. ML021760011).

6.5 US NRC, “Issuance of Amendments Regarding Adoption of TSTF-510, ‘Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection,’ TAC NOS. ME9106 and ME 9107,” Amendment No. 255, Renewed License No. DPR-31 for Unit 3, and Amendment No. 251, Renewed License No. DPR-41 for Unit 4, November 6, 2012, (ADAMS Accession # ML12297A240)

6.6 EPRI Report 3002007571, Steam Generator Management Program (SGMP): Steam Generator Integrity Assessment Guidelines, Revision 4, June 2016.

6.7 SGMP Information Letter on an Example Methodology for Screening of Alloy 600TT Tubing for the Seabrook Elevated Residual Stress Issue”, Lawrence Womack, September 14, 2004.

6.8 AREVA (proprietary) Document: 51-5026697-001, Screening for High Residual Stress Condition Tubes PTN Unit 3, March 2017.

6.9 NRC Letter to Turkey Point Nuclear Generating Station Unit Nos. 3 and 4 – Issuance of Amendments Regarding Permanent Alternate Repair Criteria for Steam Generator Tubes, TAC NOS. ME8515 and ME 8516, Amendment No. 254, Renewed License No. DPR-31 for Unit 3, and Amendment No. 250, Renewed License No. DPR-41 for Unit 4, November 5, 2012

ATTACHMENT 1

PROPOSED TECHNICAL SPECIFICATION PAGES (MARKUP)

(1 page follows)

ADMINISTRATIVE CONTROLS

PROCEDURES AND PROGRAMS (Continued)

d. Provisions for SG tube inspections. 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 plugging criteria. The portion of the tube below 18.11 inches from the top of the tubesheet is excluded from inspection. The tube-to- tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection 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 tube 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 installation.

Add single asterisk (*)

2. After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections).* In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period beings at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;
b) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

Add double asterisk (**)

c. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months.** This constitutes the third and subsequent inspection periods.

* One-time extension for Unit 3 to perform SG inspections during the Cycle 32 refueling outage in Fall 2021

** One-time extension of the 4th inspection period for Unit 3 until the Cycle 32 refueling outage in Fall 2021.