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10 CFR 50.90

June, 18, 2021
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LAR S21-03

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Salem Generating Station, Unit 2
Renewed Facility Operating License No. DPR-75
NRC Docket No. 50-311

Subject: **One-Time License Amendment Request to Revise Unit 2 Technical Specification Action for Rod Position Indicators**

In accordance with the provisions of 10 CFR 50.90, PSEG Nuclear LLC (PSEG) is submitting a request for an amendment to the Technical Specifications (TS) for Salem Generating Station (Salem) Unit 2.

The proposed change will revise Salem Unit 2 Technical Specification (TS) 3.1.3.2.1, "Position Indication Systems – Operating," to modify TS Action b.4 for more than one inoperable analog rod position indicator per group from 24 hours to 30 hours. This is a one-time change during the current operating cycle to support maintenance on the transformer supplying power to all of the Unit 2 rod position indicators.

The Enclosure provides a description and assessment of the proposed changes. Attachment 1 provides the existing TS pages marked up to show the proposed changes. No TS Bases changes are required.

PSEG is requesting approval of the proposed TS change on an expedited basis. Approval of this license amendment request (LAR) is requested by July 26, 2021. The expedited schedule for approval is being requested to support maintenance activities and avoid an unnecessary plant shutdown should transformer repairs be required for the transformer during plant operation. Once approved, the amendment will be implemented within 5 days from the date of issuance.

In accordance with 10 CFR 50.91, a copy of this application, with attachments, is being provided to the designated State of New Jersey Official.

There are no regulatory commitments contained in this letter.

10 CFR 50.90

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 6/18/21
(Date)

Respectfully,

David Sharbaugh
Site Vice President
Salem Generating Station

Enclosure: Evaluation of the Proposed Changes
Attachment 1 Mark-up of Proposed Technical Specification Pages

cc:

Mr. D. Lew, Administrator, Region I, NRC
Mr. J. Kim, Project Manager, NRC
NRC Senior Resident Inspector, Salem
Ms. A Pfaff, Manager NJBNE
PSEG Corporate Commitment Tracking Coordinator
Site Commitment Tracking Coordinator

# Enclosure

# Evaluation of the Proposed Changes

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## 1.0 SUMMARY DESCRIPTION

The proposed change will revise Salem Unit 2 Technical Specification (TS) 3.1.3.2.1, “Position Indication Systems – Operating,” to modify the TS action b.4 for more than one inoperable analog rod position indicator per group from 24 hours to 30 hours. This is a one-time change during the current operating cycle to support maintenance on the transformer supplying power to all of the Unit 2 rod position indicators.

## 2.0 DETAILED DESCRIPTION

### 2.1 System Design and Operation

Salem Unit 2 has 53 rod control cluster assemblies (RCCAs) separated into shutdown rods and control rods. There are 24 shutdown rods and 29 control rods. The RCCAs are inserted into the fuel assemblies at distinct locations to uniformly control reactivity. The RCCAs (rods) are further separated into banks and groups as shown below.

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Salem Updated Final Safety Analysis Report (UFSAR) Figure 4.3-26B (Unit 2) shows the locations of the RCCAs in the core. The four control banks (A, B, C, D) are the only rods that can be operated under automatic control. All RCCAs in a group are paralleled to step simultaneously.

Control rod movement is automatically programmed to withdraw the control rods in a predetermined sequence. The control rod programming is sequenced such that as the first control rod bank being withdrawn reaches a preset position, the second control rod bank begins to move out simultaneously with the first bank. The staggered withdrawal sequence continues until the control rod banks either reach their fully withdrawn position, or reach the desired position to control axial flux. Normally all rods are fully withdrawn at full power. The programmed insertion sequence, manual or automatic, is the opposite of the withdrawal sequence (i.e., the last control rod bank out is the first control rod bank in).

The group demand counters count the pulses from the rod control system. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group.

The shutdown rod groups together with the control rod groups are capable of shutting the reactor down under all conditions. They are used in conjunction with the adjustment of soluble boron to provide shutdown margin of at least 1.3% Δk/k following a reactor trip with the most reactive rod in the fully withdrawn position.

During normal power operation, it is desirable to maintain the rods in alignment with their respective banks. This provides consistency with the assumptions of the safety analyses, maintains symmetric neutron flux and power distribution profiles, provides assurance that peaking factors are within acceptable limits and assures adequate shutdown margin.

The analog rod position indication (ARPI) senses and displays control rod position as described below. An electrical coil stack linear variable differential transformer is placed above the stepping mechanisms of the control rod magnetic jacks external to the rod/reactor coolant system pressure housing. When the associated control rod is at the bottom of the core, the magnetic coupling between primary and secondary windings of the variable differential transformer is small and there is a small voltage induced in the secondary winding. As the magnetic jacks raise the control rod, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is derived.

Direct, continuous readout of every RCCA position is presented to the operator by individual control board meter indications without the need for operator selection or switching to determine rod position. The rod position is also displayed on the plant computer.

A 5 KVA Solatron transformer (2XFR2ELC12A) provides the conditioned voltage input for the Unit 2 analog rod position indicators (ARPIs). The Solatron regulating transformer provides a stable voltage that drives the primary coils of the ARPI system. The primary coil induces a voltage on the secondary coil relative to the position of the rod, and the ARPI signal conditioning module compares the primary and secondary coil voltages to determine rod position.

## 2.2 Current Technical Specification Requirements

The current Salem Unit 2 TS 3.1.3.2.1 action b for rod position indication is as follows:

<u>ACTION</u>:

b. With two or more analog rod position indicators per group inoperable:

1. Immediately place the control rods in manual control, and
2. Deleted
3. Verify the position of the rods with inoperable position indicators indirectly using the power distribution monitoring system (if power is above 25% RTP) or using the movable incore detectors (if power is less than 25% RTP or the power distribution monitoring system is inoperable) at least once per 8 hours, and
4. Within 24 hours restore the inoperable rod position indicators to OPERABLE status such that a maximum of one rod position indicator per group is inoperable, or
5. Be in HOT STANDBY within the next 6 hours.

## 2.3 Reason for Proposed Change

During the current Salem Unit 2 25th operating cycle, a degrading output voltage was identified on the 5 KVA Solatron transformer (2XFR2ELC12A) that provides the conditioned voltage input for the Unit 2 analog rod position indicators (ARPIs). An adverse condition monitoring (ACM) plan was established to monitor the output voltage of the transformer and make adjustments to the ARPIs following determination of rod position based on performance of incore flux mapping in accordance with the CHANNEL CALIBRATION Surveillance Requirement (SR) 4.1.3.2.1.2.

The ARPI is dependent on a stable, regulated voltage at the output of the Solatron transformer in order to accurately provide rod position. Any changes in Solatron output voltage result in changes in the indication of rod position.

The Salem Unit 2 degraded Solatron transformer output voltage was identified as an extent of condition from a Salem Unit 1 rod position indication deviation that resulted in the replacement of the Unit 1 ARPI Solatron transformer during the Unit 1 refueling outage in September of 2020 due to degrading output voltage. Maintenance assessment of the removed Unit 1 transformer identified a failed internal capacitor as the cause of the transformer's degraded output voltage.

Based on the operating experience from Unit 1 described above as well as documentation within the vendor manual for the Solatron transformer, the most likely cause of the degraded Unit 2 transformer output voltage was determined to be degrading capacitors within the transformer assembly. The Unit 2 Solatron transformer is planned for replacement in the Fall 2021 refueling outage.

Repair plans have been developed to implement the replacement of all capacitors within the Unit 2 Solatron transformer in the event of an emergent failure with a contingency to fully replace the transformer. Replacement of the transformer internal capacitors can be accomplished in a shorter period of time than replacement of the entire transformer. The repair requires the tagging and deenergization of the Solatron transformer which results in the inoperability of all Unit 2 ARPIs. Recent work planning evaluations concluded the duration of corrective maintenance and required retesting may exceed the 24 hour allowed outage time.

<u>Expedited Review Circumstances</u>

Expedited approval is being requested to support this emergent repair for the Unit 2 rod position indicators during plant operation should further degradation of the ARPI voltage input result in entry into Action b of TS 3.1.3.2.1. Inoperability of more than one rod position indicator per bank for more than 24 hours requires a plant shutdown within the next six hours. Expedited NRC review of this proposed amendment could avoid an unnecessary reactor shutdown with the Unit 2 ARPIs inoperable. If transformer performance does not require online repair during the remainder of the current operating cycle, the ARPI Solatron transformer will be replaced during the upcoming Unit 2 refueling outage scheduled in October 2021. If Salem Unit 2 is required to perform an emergent plant shutdown to Mode 3 or lower prior to the refueling outage, the transformer will be repaired prior to plant startup from the forced outage and the extended allowed outage time will no longer be applicable.

While the ARPIs remain OPERABLE and capable of determining the actual rod positions, recent work planning evaluation showed the time required for corrective maintenance and retesting in the event of an emergent failure would challenge the allowed outage time and provide little margin for contingencies. The extended allowed outage time would prevent an unnecessary plant shutdown without a corresponding health and safety benefit.

2.4 Description of Proposed Change

The proposed change to the Salem Unit 2 TS is described below and indicated on the marked up TS page provided in Attachment 1 of this submittal. Additions are marked with underlining.

<u>ACTION</u>:

b. With two or more analog rod position indicators per group inoperable:

1. Immediately place the control rods in manual control, and

2. Deleted

3. Verify the position of the rods with inoperable position indicators indirectly using the power distribution monitoring system (if power is above 25% RTP) or using the movable incore detectors (if power is less than 25% RTP or the power distribution monitoring system is inoperable) at least once per 8 hours, and

4. Within 24 hours<u>*</u> restore the inoperable rod position indicator(s) to OPERABLE status such that a maximum of one rod position indicator per group is inoperable, or

5. Be in HOT STANDBY within the next 6 hours.

<u>* During the Unit 2 25th operating cycle, a one-time 30 hour allowed outage time is permitted to allow repair of the rod position indication Solatron transformer. This one-time change will cease to apply if Unit 2 enters Mode 3 prior to the S2R25 refueling outage.</u>

## 3.0 TECHNICAL EVALUATION

3.1 Deterministic Basis for One-Time AOT Extension

Salem Unit 2 TS 3.1.3.2.1 action b.4 allows 24 hours to restore rod indication when two or more position indicators in a group are inoperable. Salem Unit 2 TS 3.1.3.2.1 is consistent with TS 3.1.7, Rod Position Indication, (Reference 1) in NUREG-1431, “Standard Technical Specifications – Westinghouse Plants.”

As discussed in the NUREG-1431 bases for TS 3.1.7, LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits. The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available shutdown margin (SDM). Rod position indication is required to assess OPERABILITY and misalignment. Control and shutdown rod position accuracy is essential during power operation. The rod positions must also be known in order to verify the alignment limits are preserved. Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

With more than one RPI per group failed, additional actions are necessary to ensure that acceptable power distribution limits are maintained, minimum SDM is maintained, and the potential effects of rod misalignment on associated accident analyses are limited. Placing the Rod Control System in manual assures unplanned rod motion will not occur and together with the indirect position determination available via movable incore detectors will minimize the potential for rod misalignment.

The position of the rods may be determined indirectly by use of the movable incore detectors. Verification of control rod position once per 8 hours is adequate for allowing continued full power operation for a limited period, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small. Normally the Completion Time provides sufficient time to troubleshoot and restore the RPI system to operation while avoiding the plant challenges associated with the shutdown without full rod position indication. Based on operating experience, normal power operation does not require excessive rod movement.

During the Unit 2 ARPI transformer maintenance window, all other reactivity monitoring systems will be available with the Unit remaining at steady state power. Diverse systems will remain OPERABLE to assist in detection of gross rod misalignment such as Axial Flux Differential (AFD) and Quadrant Power Tilt Ratio (QPTR) Monitor/Alarms, Power Range (PR) Nuclear Instrumentation, AFD console indication, as well as Plant Computer AFD and QPTR indications.

Although power will be removed from the ARPI during the maintenance window, the group demand counter indication will remain available on the console and plant computer.

The additional time of 6 hours for a total allowed outage time of 30 hours to restore the inoperable ARPI is appropriate because TS 3.1.3.2.1 action b.1 requires that the control rods be under manual control preventing automatic rod movement, and TS 3.1.3.2.1 action b.3 requires that rod position be verified indirectly every 8 hours thereafter, thereby assuring that the rod alignment (Unit 2 TS 3.1.3.1) and rod insertion limit (Units TS 3.1.3.4 and 3.1.3.5) LCOs are met. Therefore, the required shutdown margin will be maintained.

Given the alternate position monitoring requirement, and other indirect means of monitoring changes in rod position, a 30 hour completion time to restore the inoperable rod position indicators to OPERABLE status such that a maximum of one rod position indicator per group is inoperable provides sufficient time to restore operability while minimizing shutdown transients during the time that the position indication system is degraded.

3.2 Timeline of maintenance window

The task durations identified in the Table below are based on established testing durations and recent experience in replacing the same transformer on Unit 1 during the Fall 2020 refueling outage. The tasks include transformer replacement online as a contingency in the event capacitor replacement does not correct the transformer output voltage.

| Task | Task Duration (hrs.) | Elapsed TS Action Time (hrs.) |
|---|---|---|
| Enter TS 3.1.3.2.1 Action b | 0 | 0 |
| Apply Clearance | 2 | 2 |
| Replace Capacitors | 4 | 6 |
| Remove Clearance | 2 | 8 |
| Voltage Check of Transformer Output | 1 | 9 |
| Re-apply Clearance | 2 | 11 |
| Rig and Stage Transformer | 4 | 15 |
| Replace Transformer | 4 | 19 |
| Remove Clearance | 2 | 21 |
| Voltage Check of Transformer | 1 | 22 |
| All Rods Out Position Check | 1 | 23 |
| ARPI Channel Calibration | 6 | 29 |
| ARPI Declared Operable | 1 | 30 |

The above schedule has been challenged through the work management process providing confidence in the tasks and durations for the repair evolution. Clearance (tagging) documents have been prepared. Replacement capacitors have been pulled from stores, tested and staged for the replacement. Guidance has also been developed to assist in the internal wiring of the capacitors in the transformer housing. A replacement transformer has been verified ready in the event that transformer replacement is required.

3.3 Risk Insights for One-Time AOT Extension

Although this license amendment request is not a risk-informed request and therefore a risk evaluation is not required, PSEG is providing supplemental risk insights related to the proposed change.

3.3.1 Technical Acceptability of PRA Model

Salem currently only uses a full power internal events (FPIE) PRA model; there are no other approved PRA models for Salem. The modified Salem FPIE PRA model of record (MOR), SA115D, is acceptable to evaluate the AOT extension. The Salem FPIE PRA modeling is highly detailed, including a wide variety of initiating events, modeled systems, operator actions, and common cause events. The PRA model quantification process used for the PRA is based on the event tree/fault tree methodology. In November 2008, a Pressurized Water Reactors Group (PWROG) team completed a peer review of the Salem Revision 4.1 PRA Model using the Nuclear Energy Institute (NEI) process for performing follow-on PRA peer reviews to determine compliance with Part 2 and Part 3 of the ASME PRA Standard and Regulatory Guide (RG) 1.200. The peer review identified Finding-level Facts and Observations (F&O) and by January 2019, all open F&Os were resolved and considered closed by the F&O Closure Team, which was documented in the F&O Closure Team's independent assessment and focused-scope peer review report. Since all F&Os were resolved and peer reviewed, the SA115D FPIE PRA model is deemed acceptable to perform a risk evaluation for this one-time AOT extension.

3.3.2 Regulatory Guidance

RG 1.177 specifies an approach and acceptance guidelines for the evaluation of plant licensing basis changes. RG 1.177 identifies a three-tiered approach for the evaluation of the risk associated with a proposed TS change:

- Tier 1 addresses risk metric requirements for one-time TS completion time changes of incremental conditional core damage probability (ICCDP) less than 1.00E-6 and incremental conditional large early release probability (ICLERP) less than 1.00E-7.
- Tier 2 identifies and evaluates any potential risk significant plant equipment outage configurations associated with the proposed plant change.
- Tier 3 provides for the establishment of a configuration risk management program.

3.3.3 Risk Evaluation

Full Power Internal Events

The ARPI system is not modeled in the Salem PRA because its failure does not result in or cause a core damage or large, early release accident sequence. Removing the ARPI system from service does not render a core damage mitigation function or a large, early release mitigation function unavailable. Additionally, the degradation of ARPI does not affect the ability of an operator to perform a mitigation action in the event of a PRA-modeled transient.

However, since the unavailability of the ARPI transformer will result in a loss of a backup reactor trip verification method (i.e., rod bottom lights lit), a sensitivity analysis was performed. This sensitivity analysis assumes that loss of ARPI increases the probability of the operators failing to manually trip the reactor in an Anticipated Transient Without Scram (ATWS) scenario, which is a conservative assumption since operations do not rely on ARPI for ATWS determination. To capture this effect, the failure rate of human error probability (HEP) MCB-XHE was adjusted to its 95$^{th}$ percentile value. Also, it was decided to conservatively assess any associated human failure event (HFE) combinations involving MCB-XHE with other associated reactivity control HFEs as having complete dependence, and any long-term HFEs not associated with reactivity control were assessed with their nominal dependence. This effectively assumed complete dependence between MCB-XHE and the following HFEs: BUS-XHE, MG-XHE, and MRI-XHE.

Additionally, the frequency of the initiating event for a transient with Power Conversion System (PCS) unavailable was increased to account for the possibility that compensatory actions increase the likelihood of a plant trip. Operators rely upon movement of the control rods in the event of certain secondary plant transients (e.g., feedwater pump runback). If such a condition occurs while ARPI is unavailable, the operators may trip the plant rather than control the plant using manual rod insertion. To capture this effect, the frequency of the initiating event for a transient with PCS unavailable (%TP) was increased by one occurrence per year.

These adjustments, as shown in Table 1 below, represent the plant-specific configuration for loss of ARPI and are considered conservative, bounding values that represent the upper bound of the risk impact of this configuration.

**Table 1: Adjusted PRA Events**

| PRA Event | Description | Base Probability | Sensitivity Probability |
|---|---|---|---|
| MCB-XHE | MANUAL REACTOR TRIP FAILS | 1.00E-02 | 2.93E-02 |
| %TP | TRANSIENT WITH PCS UNAVAILABLE INITIATOR | 1.68E-01/yr | 1.17E+00/yr |

The average maintenance PRA model was used to calculate ICCDP and ICLERP. The ICCDP and ICLERP are computed using the definitions in RG 1.177. The formulas are as follows:

$$ICCDP_{ARPI} = (CDF_{ARPI} - CDF_{BASE}) * \Delta T,$$

$ICCDP_{ARPI}$ is the ICCDP with ARPI unavailable

$CDF_{ARPI}$ is the CDF computed with increased %TP frequency and the 95$^{th}$ percentile value for failure to manually trip the reactor (MCB-XHE)

$CDF_{BASE}$ is average-maintenance case baseline CDF

$\Delta T$ is the extension of the CT converted to units consistent with the CDF frequency units (48 hours * 1 day / 24 hours * 1 year / 365 days = 5.48E-03 year)

$$ICLERP_{ARPI} = (LERF_{ARPI} - LERF_{BASE}) * \Delta T,$$

$ICLERP_{ARPI}$ is the ICLERP with ARPI unavailable

$LERF_{ARPI}$ is the LERF computed with increased %TP frequency and the 95$^{th}$ percentile value for failure to manually trip the reactor (MCB-XHE)

$LERF_{BASE}$ is average-maintenance case baseline LERF

$\Delta T$ is the extension of the CT converted to units consistent with the CDF frequency units (48 hours * 1 day / 24 hours * 1 year / 365 days = 5.48E-03 year)

Seismic

As an additional set of stand-alone calculations, the potential impact of seismic events on the risk assessment is considered using inputs from the FPIE PRA model. The primary seismic events of interest for this assessment are a Loss of Offsite Power (LOOP) or an induced Small Loss of Coolant Accident (LOCA). The largest seismic events are expected to cause Larger LOCAs and additional failures, making small changes in the availability to manually trip the reactor a negligible impact.

The frequency of a seismically-induced LOOP is 2.19E-05 per year from all categories of seismic events. Assuming that all seismic events that cause a LOOP would also cause a Small LOCA, a seismically-induced LOCA event is conservatively assumed to be the same frequency as a seismically-induced LOOP. These parameters are discussed in detail in PSEG letter to NRC, "License Amendment Request: Vital Instrument Bus Inverter Allowed Outage Time (AOT) Extension," dated May 16, 2018 (ADAMS Accession No. ML18136A866)

To quantify the seismic risk as a result of the loss of ARPI, the PRA gate CE (ATWS due to electrical faults) in the FPIE PRA model was quantified using the baseline and ARPI configuration to derive the change in risk. The total seismic risk is the product of the sum of the seismically-induced LOOP and seismically-induced LOCA frequency, the change in gate CE probability, and the AOT.

ICCDP = f(Seismic LOCA+LOOP) x $\Delta$CE x $\Delta$T,

f(Seismic LOCA+LOOP) = 4.38E-05

$\Delta CE = CE_{ARPI} - CE_{BASE}$ = 2.71E-07

$\Delta$T = 5.48E-03

Assuming that all CDF sequences go to LERF for seismic risk, ICLERP = ICCDP. The quantification results are presented in Table 2.

Fire

The fire ignition frequencies used for this calculation are from the current work-in-progress fire PRA. The plant-specific internal fire boundaries have been identified and the physical analysis units have been defined in accordance with NUREG/CR-6850. The fire ignition frequencies have been calculated from Supplement 1 of NUREG/CR-6850 (FAQ 08-0048) and NUREG-2169.

A similar approach as the seismic risk discussed above is used to calculate the change in fire risk.

ICCDP = f(Fire) x $\Delta$CE x $\Delta$T,

f(Fire) = 4.62E-01 (based on NRC guidance as discussed above)

$\Delta CE = CE_{ARPI} - CE_{BASE}$ = 2.71E-07

$\Delta$T = 5.48E-03

Assuming that all CDF sequences go to LERF for fire risk, ICLERP = ICCDP. The quantification results are presented in Table 2.

Other External Events

External events other than internal fires (i.e., external fires, external flooding, high winds, tornado, transportation, and other nearby facility accidents) do not need special probabilistic treatment for ARPI failures at Salem. All rod control and indication equipment are well-protected from all external events other than internal fires.

Salem does not currently have an external flood PRA model. However, seismic and flood events were considered, and it was determined that there is a negligible increase in risk for ARPI unavailability. In the IPEEE, these external events were assumed to lead to a loss of offsite power. If an ATWS occurred, the scenario was assumed to go to core damage with certainty. Because the initiating event frequencies for external events are much lower than those for internal events, combined with the short duration of the extended AOT, the risk from external events was seen as a much smaller contributor. As a result, a flood event would have negligible changes in risk similar to what was shown above for seismic.

Results

The Salem FPIE PRA model was quantified with the adjustments presented in Table 1 and the HFE dependencies previously discussed. It is noted that all quantified cases did not take credit for Salem Unit 3 (“Jet”), C Emergency Diesel Generator (EDG) recovery (failure to recover power to a FOTP using the FLEX DG to fuel the C EDG during an ELAP), nor RCP shutdown seals. The ICCDP and ICLERP results for 48 hours are reported in Table 2. Since there are no other PRA models for Salem, internal fires risk and other external events risk were quantified using bounding assumptions and the FPIE PRA.

**Table 2: Quantification Results**

| **CDF** | **Baseline Results (/yr)** | **ARPI Unavailable Results (/yr)** | **Delta (Δ) (/yr)** | **ICCDP** | **Acceptance Guidelines** |
|---|---|---|---|---|---|
| Internal Events | 1.4060E-05 | 1.5012E-05 | 9.52E-07 | 5.22E-09 | -- |
| Fire | 1.1661E-08 | 1.3670E-07 | 1.25E-07 | 6.85E-10 | -- |
| Seismic | 1.1056E-12 | 1.2960E-11 | 1.19E-11 | 6.50E-14 | -- |
| Total | 1.4072E-05 | 1.5149E-05 | 1.08E-06 | **5.90E-09** | 1E-06 |
| **LERF** | **Baseline Results (/yr)** | **ARPI Unavailable Results (/yr)** | **Delta (Δ) (/yr)** | **ICLERP** | **Acceptance Guidelines** |
| Internal Events | 6.4593E-07 | 6.8037E-07 | 3.44E-08 | 1.89E-10 | -- |
| Fire | 1.1661E-08 | 1.3670E-07 | 1.25E-07 | 6.85E-10 | -- |
| Seismic | 1.1056E-12 | 1.2960E-11 | 1.19E-11 | 6.50E-14 | -- |
| Total | 6.5759E-07 | 8.1708E-07 | 1.59E-07 | **8.74E-10** | 1E-07 |

The results demonstrate that there is no impact to the risk metrics, as the ICCDP and ICLERP are below the acceptance criterion of 1E-06 and 1E-07 for ICCDP and ICLERP, respectively. Additional risk insights from cutset reviews show that majority of the risk (>80%) is attributed to the common cause failures of the RPS circuitry (>70%) and the reactor trip breakers (>10%). The highest risk increases are for internal initiating events, because their frequency is much higher and the ATWS risk is proportional to the trip frequency.

The key uncertainty in this calculation is the increased frequency of initiating event for a transient with PCS unavailable (%TP), which is based on judgement because there is no reliable data source to use for this estimate. The calculation results demonstrate that the frequency %TP can be increased significantly (at least 100-fold) with sufficient margin to the acceptance guidelines.

3.3.4 Risk-Significant Configurations (Tier 2)

During the Unit 2 ARPI Transformer maintenance window, all other reactivity monitoring systems will be available with the Unit remaining at steady state full power. Diverse systems will remain operable to assist in detection of gross rod misalignment such as Axial Flux Differential (AFD) and Quadrant Power Tilt Ratio (QPTR) Monitor/Alarms, Power Range (PR) Nuclear Instrumentation, AFD console indication, as well as Plant Computer AFD and QPTR indications. Group demand counter indication will remain available on the console and plant computer. Rod positions will be verified in accordance with the TS 3.1.3.2.1 action b.3. The frequency for verifying rod positions is based on operating experience and equipment reliability which satisfies all accident analysis assumptions concerning rod position and therefore will not create undue risk to the public health and safety, adverse consequences to the environment, and provide assurance of fuel rod integrity during continued operation during the 2 ARPI transformer repair window.

Based on the configuration described above, there exists sufficient defense-in-depth with the loss of ARPI, as redundancy and independence exists within reactivity monitoring systems.

3.3.5 Configuration Risk Management Program (Tier 3)

Implementation of the Salem Configuration Risk Management Program, which meets the requirements in Regulatory Guide 1.177 Section 2.3.7.2, helps to ensure there is no significant risk increase while maintenance is being performed. This tier is important because all possible risk-significant configurations under Tier 2 cannot be predicted. Salem implements the applicable portions of the Maintenance Rule by using the endorsed guidance of Section 11.0 of NUMARC 93-01.

Salem uses the Phoenix Configuration Risk Monitor program from the Electric Power Research Institute (EPRI) to implement 10 CFR 50.65(a)(4). Phoenix uses the same fault trees and database as the internal events PRA model, so it is fully capable of evaluating CDF for internal events. The loading and use of Phoenix is procedurally controlled by the PSEG PRA procedures.

Salem procedures recognize there are limitations in Phoenix and specifically direct consideration of external events and site activities that can result in significant plant events. Some conditions are evaluated in Phoenix through multiplication factors; others procedurally lead to other remedial actions including plant color changes. Fire risk management actions, which are governed by the same set of procedures and implemented by the same staff, are determined from the deterministic fire safe shutdown procedures from 10 CFR 50 Appendix R. When maintenance or testing is scheduled, the Operations, Work Week Management and Site Risk Management staff perform and review weekly risk analyses using the Phoenix program. For unplanned or emerging equipment failures, control room personnel will enter the configuration into the Phoenix. In either case, the configuration will be evaluated to assess and manage the risk.

Risk associated with unavailable plant equipment is assessed at Salem as required by 10 CFR 50.65(a)(4). The PSEG work management administrative procedure governs on-line risk assessments. The on-line risk assessment is a blended approach using qualitative or defense-in-depth considerations and quantifiable PRA risk insights when available to complement the qualitative assessment. Salem communicates on-line plant risk using three risk tiers (GREEN, YELLOW, and RED).

Protecting equipment requires posting of signs and robust barriers to alert personnel not to approach the protected equipment. Work on protected equipment is generally disallowed. Minor exceptions exist for activities such as inspections, security patrols, or emergency operations. Other exceptions may be authorized by the station shift manager in writing. If additional unplanned equipment unavailability occurs, station procedures direct that the risk be re-evaluated, and if found to be unacceptable, compensatory actions are taken until such a time that the risk is reduced to an acceptable level.

Procedure OP-AA-108-116 directs the Operations and Work Management personnel to routinely monitor various maintenance configurations and protect equipment that could lead to an elevated risk condition (e.g., “red” risk condition) if it were to become unavailable due to unplanned or emergent conditions. This is normally accomplished using the Phoenix PRA software tool, supplemented by operations and work management procedures.

3.3.6 Recommendations

Based on the increased risk created by the Unit 2 ARPI repair window, the following risk management actions will be taken:

- Control Rods will be maintained in manual per TS 3.1.3.2.1 action b.1 to prevent automatic rod motion.
- Reactor Engineering will verify rod position in accordance with TS 3.1.3.2.1 action b.3. Additionally, reactor engineering will perform a rod position verification following plant stabilization from any emergent power maneuver in response to a plant transient.
- Main control room operators will perform additional monitoring of diverse parameters that assist in the detection of gross rod misalignment such as hourly monitoring of Power Range Nuclear Instruments (PRNI’s), AFD (Axial Flux Differential) Quadrant Power Tilt Ratio (QPTR), and group demand counters. An operator will be dedicated to continuously monitoring AFD and QPTR on the Plant Computer during any power changes.
- Control Room Operators will be briefed on performing Reactor Trip Confirmation according to current training. Operators are trained to verify a reactor trip using multiple and diverse indications which include, PRNI’s, Intermediate Range Nuclear Instrument power level and startup rate, Rod Bottom Lights, and Reactor Trip breaker position. Based on the diversity of the remaining available indications, the unavailability of the ARPIs will not impact the operator’s ability to respond to an ATWS event. These established verifications will ensure successful reactor trip confirmation if required.
- Reactor Engineering will remain on-station, after call-in, to support rod position verifications via flux mapping during the Unit 2 ARPI Transformer repair window. This will ensure success in monitoring for proper rod-alignment in the event the operating crew is required to change power in response to an event or perform an orderly shutdown.
- All Unit 2 work will be re-screened to identify operational or reactivity risk vulnerabilities that could potentially cause a plant or reactivity transient. This work will be re-scheduled accordingly to reduce the likelihood that the control room operators would need to change reactor power while ARPIs are unavailable.

3.3.7 PRA Insight Conclusion

The following conclusions were reached as a result of this evaluation:

- All quantitative results for ICCDP and ICLERP for the allowed outage time extension are less than the acceptance guidelines.

- The PRA models are acceptable to support this evaluation and the resulting risk is acceptable and consistent with the NRC safety goals.

- Prudent risk management actions are proposed. The actions have not been quantified in the PRA model but are judged to further reduce the risk for this plant configuration.

3.4 Conclusion

In summary, a 30 hour completion time to restore the inoperable rod position indicators to OPERABLE status such that a maximum of one rod position indicator per group is inoperable provides sufficient time to restore operability while minimizing the potential for shutdown transients during the time that the position indication system is degraded given the alternate position monitoring requirement, and other indirect means of monitoring changes in rod position. Knowing the position of the rods ensures alignment with their respective banks and the assumption of the safety analysis; therefore, the required shutdown margin will be maintained.

## 4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

10 CFR 50, Appendix A, General Design Criteria (GDC)

Salem was designed and constructed in accordance with Atomic Energy Commission (AEC) proposed General Design Criteria published in July 1967. The applicable AEC proposed criteria, as document in Salem UFSAR Section 3.1, were compared to 10 CFR 50 Appendix A General Design Criteria (GDC) as discussed below. The applicable GDC criterion is GDC-13.

*Criterion 13—Instrumentation and control*. Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

GDC Criterion 13 is similar to AEC Criterion 12.

Following implementation of the proposed change, Salem Unit 2 will remain in compliance with AEC Criterion 12.

4.2 Precedent

None

4.3 No Significant Hazards Consideration

PSEG requests an amendment to the Salem Unit 2 Operating License. The proposed change will revise Salem Unit 2 Technical Specification (TS) 3.1.3.2.1, “Position Indication Systems – Operating,” to modify the allowed outage time in TS action b.4 for more than one inoperable analog rod position indicator per group from 24 hours to 30 hours. This is one-time change during the current operating cycle to support maintenance on the transformer supplying regulated voltage to all of the Unit 2 rod position indicators.

PSEG has evaluated the proposed change to the TS using the criteria in 10 CFR 50.92, and determined that the proposed change do not involve a significant hazards consideration. The following information is provided to support a finding of no significant hazards:

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

   Response: No

   Rod position indication instrumentation is not an accident initiator, providing indication only of the control and shutdown rods positions. Normal operation, abnormal occurrences and accident analyses assume the rods are at certain positions within the reactor core. The proposed one-time change modifies the time that rod position indication may be inoperable. The existing TS Actions and other plant instrumentation provide appropriate compensation for that inoperability. Thus, this change does not involve a significant increase in the probability of an accident.

   Extending the allowed outage time to restore inoperable rod position indicators does not affect the operability of the shutdown or control rods. With rod position indicators inoperable, the position of non-indicating rods is required to be verified by indirect means (i.e., moveable incore detectors). Thus, inoperable rod position indication instrumentation does not involve an increase in the consequences of an accident. The inoperable rod position indication does not have any impact on the ability to trip the reactor in response to analyzed accidents and transients.

   Therefore, the proposed change does not represent 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?

   Response: No

   The proposed change does not alter the design, function, or operation of any plant component and does not install any new or different equipment. The proposed change will not impose any new or different requirement or introduce a new accident initiator, accident precursor, or malfunction mechanism.

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

3. Do the proposed changes involve a significant reduction in a margin of safety?

   Response: No

   Loss of rod position indication does not cause a rod to be misaligned. With rod position indicators inoperable, the control rods are required to be placed in manual control, and the position of non-indicating rods is required to be verified using indirect means. The proposed change will not affect the ability of the shutdown or control rods to perform their required function.

   The proposed amendment will not result in a design basis or safety limit being exceeded or altered. Therefore, since the proposed change does not impact the response of the plant to a design basis accident, the proposed change does not involve a significant reduction in a margin of safety.

Based upon the above, PSEG concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of “no significant hazards consideration” is justified.

4.4 Conclusion

Therefore, 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

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change 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 effluent 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

1. NUREG-1431, Revision 4.0, Standard Technical Specifications Westinghouse Plants, April 2012

## Attachment 1

## Mark-up of Proposed Technical Specification Pages

The following Technical Specifications pages for Renewed Facility Operating License DPR-75 are affected by this change request:

| **Technical Specification** | **Page** |
| --- | --- |
| 3.1.3.2.1, Position Indication Systems - Operating | 3/4 1-16a |

LIMITING CONDITION FOR OPERATION (Continued)

3. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

b. With two or more analog rod position indicators per group inoperable:

1. Immediately place the control rods in manual control, and

2. Deleted

3. Verify the position of the rods with inoperable position indicators indirectly using the power distribution monitoring system (if power is above 25% RTP) or using the movable incore detectors (if power is less than 25% RTP or the power distribution monitoring system is inoperable) at least once per 8 hours, and

4. Within 24 hours* restore the inoperable rod position indicators to OPERABLE status such that a maximum of one rod position indicator per group is inoperable, or

5. Be in HOT STANDBY within the next 6 hours.

c. When one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the last determination of the rod's position:

1. Determine the position of the non-indicating rod(s) indirectly using the power distribution monitoring system (if power is above 25% RTP) or using the movable incore detectors (if power is less than 25% RTP or the power distribution monitoring system is inoperable) within 8 hours, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

d. With a maximum of one group demand position indicator per bank inoperable either:

1. Verify that all analog rod position indicators for the affected bank are OPERABLE and that the most withdrawn rod and the least withdrawn rod of the bank are within a maximum of 18 steps when reactor power is ≤ 85% RATED THERMAL POWER or if reactor power is > 85% RATED THERMAL POWER, 12 steps of each other at least once per 8 hours, or

2. Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER within 8 hours.

* During the Unit 2 25th operating cycle, a one-time 30 hour allowed outage time is permitted to allow repair of the rod position indication Solatron transformer. This one-time change will cease to apply if Unit 2 enters Mode 3 prior to the S2R25 refueling outage.