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OFFICE OF ENFORCEMENT~~

ENFORCEMENT

PANEL MATERIAL

REGION I DATE 7/25

CASES	ASSIGNED TO
1. David Klepadlo + Assoc	SM
2. IP-2	DN
3.	
4.	
5.	

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DD/12

From: Gina Matakas
To: Enforcement, John McGrath, Leanne Harrison, Sco...
Date: Thu, Jul 20, 2000 3:05 PM
Subject: Region I Enforcement Panels - Tuesday, July 25

~~PRE-DECISIONAL ENFORCEMENT INFORMATION - DO NOT DISCLOSE~~

There is one materials case and one reactor case scheduled for next week. The panel meetings will be held on Tuesday, July 25, beginning at 1:00 p.m. The enforcement panel schedule is attached.

1:00 p.m. - David D. Klepadlo & Assocoates - OI Out-Brief - False Information - no material attached SM

1:30 p.m. - Indian Point 2 - Steam Generator Tube Failure - Information will be provided later. DN

The bridge number for the panel on Tuesday is: 301-231-5539 - PASSCODE: 6656#

ENFORCEMENT/SDP PANEL SCHEDULE FOR
TUESDAY - JULY 25, 2000 AT 1:00 P.M.

~~DO NOT DISCLOSE~~
~~CONTAINS SENSITIVE, PRE-DECISIONAL ENFORCEMENT AND/OR OI INFORMATION~~

REGIONAL ATTENDEES

TIME	LICENSEE	ISSUES	(EO/ES AND D OR D/D ALWAYS) DRS	MIS	OTHER	DRP	DNMS
1:00 p.m.	David D. Klepadlo & Assts.	OI Out-brief - False Information				OI - L	X OE OGC
1:30 p.m.	Indian Point 2	Steam Generator Tube Failure				X	L OE

THE BRIDGE NO. FOR THE PANEL MEETING IS: (301) 231-5539 - PASS CODE 6656#

THE PANELS WILL BE HELD IN THE "EXECUTIVE CONFERENCE ROOM"
L = LEAD DIVISION X = OTHERS

G:\ENFPANEL-0725.WPD

Book 1

EGM 96-003: STEAM GENERATOR TUBE INSPECTIONS

(Updated June 1, 2000)

→ **NOTE**: This guidance was originally issued on September 26, 1996. It has been updated to reflect recent Enforcement Policy revisions and current enforcement practices.

This guidance should be used to address violations that, for whatever reason, are not addressed within the reactor oversight process and the significance determination process.

This memorandum is being issued to provide enforcement guidance for evaluating enforcement issues that may be raised during the review of licensee steam generator (SG) inspections in the areas of steam generator tube surveillance, maintenance, and related program issues. The enclosed guidance regarding the severity level classification primarily focuses on applying Appendix B criteria to SG findings, but does note that 10 CFR 50.65 (the Maintenance Rule) is applicable. The guidance has been developed in close coordination with the Division of Engineering, NRR.

Attachment 1 contains guidance in a format similar to the Supplements to the Enforcement Policy for assessing the potential severity level of noncompliances. Concerns relating to specific circumstances should be evaluated against cases contained in Attachment 2.

The guidelines in the attachments are intended to provide guidance to the NRC staff to facilitate consistent categorization of severity levels associated with SG tube problems. It is important to note that these guidelines are not currently contained in the Enforcement Policy and are, therefore, not controlling. They should be used to assist in applying the definition in Section IV of the Policy: (1) instances of very significant regulatory concerns (for Severity Level II violations), (2) significant regulatory concerns (for Severity Level III violations), or (3) more than of minor concern (for Severity Level IV violations).

The severity level guidance paragraphs in Attachment 1 use the phrase "not being able to fulfill the intended safety function," which is consistent with the Supplements to NUREG-1600. The steam generators have two different types of safety function: to provide an intact RCS boundary and prevent significant offsite releases, and to provide a means for decay heat removal. A gross failure in one SG might prevent the first safety function from being fulfilled even if the other SG(s) remained intact. However, leaks in one or more SGs might still allow the second safety function to be fulfilled by the remaining intact SG(s). Either SG safety function can be considered in determining the severity level of a violation. If both safety functions are impacted, consideration should be given to a higher severity level based on risk considerations.

To maintain consistency of enforcement in this area, all cases of violation associated with steam generator tube problems should be paneled in the weekly regional calls. The Branch Chief for Materials and Chemical Engineering Branch, Division of Engineering, NRR, is to be invited to attend the panels to provide the NRC technical perspective. Based on experience in applying this guidance, OE intends to consider appropriate changes to the guidance and changes to the Enforcement Policy after consultation with the Commission.

Attachments: As stated

ATTACHMENT 1: STEAM GENERATOR TUBE INSPECTION VIOLATIONS

The steam generators have two different types of safety function: to provide an intact RCS boundary and prevent significant offsite releases, and to provide a means for decay heat removal. A gross failure in one SG might prevent the first safety function from being fulfilled even if the other SG(s) remained intact. However, leaks in one or more SGs might still allow the second safety function to be fulfilled by the remaining intact SG(s). Either SG safety function can be considered in determining the severity level of a violation. If both safety functions are impacted, consideration should be given to a higher severity level based on risk considerations.

A. Severity Level I - Violations involving for example:

The steam generators (SGs), which are designed to support the prevention or mitigation of a serious safety event, not being able to perform the intended safety function when actually called upon to work, such as due to tube ruptures or gross structural failure, caused by licensee performance deficiencies such as inadequate assessment of or corrective actions for SG tube flaws.

B. Severity Level II - Violations involving for example:

The SGs, which are designed to support the prevention or mitigation of a serious safety event, not being able to perform the intended safety function, such as due to loss of structural integrity, caused by licensee performance deficiencies such as inadequate assessment of or corrective actions for SG tube flaws.

C. Severity Level III - Violations involving for example:

1. One SG not being able to perform its intended plant cooling safety function, such as due to loss of structural integrity.

2. The SGs are determined to be degraded to such an extent that the SGs would not have been able to perform the intended safety function under certain conditions.

D. Severity Level IV (SLIV)- Violations involving for example:

Violations in procedure adequacy, procedure adherence, or flaw dispositioning that are of more than minor concern, but which do not amount to a Severity Level I, II, or III violation.

E. Minor Violations - Violations involving for example:

Isolated procedure errors or mistakes in dispositioning of SG tube flaws with otherwise good licensee programs and good corrective actions, which did not result in exceeding TS limits and if such error or mistakes recurred, they would still be considered minor.

ATTACHMENT 2: EXAMPLE CASES

Case #1

During an outage, a licensee determined that an unexpectedly large number of SG tubes require plugging due to flaw indications that indicated that the tubes were defective (flaws concluded to be greater than the 40% through wall TS limit for returning to service). The inspector reviewed the licensee's actions, which included a re-examination of the previous outage data for the locations that now exceeded TS allowable. All previous determinations for those locations had been that there was "no detectable degradation." The re-examination concluded that one location had not been properly dispositioned during the previous outage and that the affected tube should have been plugged. The affected tube did not fail during the subsequent cycle. The inspector concluded that an inadvertent personnel error had occurred, but that the licensee's corrective actions were good.

Conclusion:

- Inadvertent personnel error - no willfulness
- One example of failure to follow procedures (Appendix B, Criterion V)
- No significant consequences or programmatic concerns
- No basis for escalated enforcement
- Potential SLIV violation, or
- Potential minor violation

Case #2

During an outage, a licensee determined that an unexpectedly large number of SG tubes require plugging due to flaw indications that indicated that the tubes were defective. The inspector reviewed the licensee's actions, which included a re-examination of the previous outage data for the spots that now exceeded TS allowable. All previous determinations for those locations had been that there was "no detectable degradation." The re-examination concluded that many locations had not been properly dispositioned during the previous outage and that the affected tubes should have been plugged.

Conclusion:

- Many examples of failure to follow procedure (Appendix B, Criterion V)
- Severity Level IV violation with multiple examples if each discrepancy was an example of a similar error; Multiple Severity Level IV violations if the errors were of a different nature for different tubes.
- Potential Severity Level III violation if the magnitude of the errors amounted to a loss of structural integrity or function (See attachment 1, item C.1 and C.2.)

Note:

- If all SGs were found to be degraded such that structural integrity could not be demonstrated, then see NUREG-1600, Supplement I.B.1. This case is represented as Attachment 1, item B.
- If structural integrity for one SG was lost, then see NUREG-1600, Supplement I.C.2. This case is represented in Attachment 1, item C.1.
- If the structural integrity was not lost but was significantly degraded in more than one SG (and included both safety trains), a SLIII may still be merited, especially if a worst case transient might have resulted in SG tube rupture(s). This case is represented as Attachment 1, item C.2.

Case #3

During an outage, a licensee applied a technology or method not previously used at the facility. A large number of defects were identified compared with inspections during previous outages. The licensee re-examined the old data and no significant dispositioning problems were identified. NRC conducted an independent review of a sample of the previous determinations.

Scenario #1 - NRC identifies no discrepancies
- Probable conclusion is that new method simply found "more"
- No violation

Scenario #2 - NRC concludes small number should have been "defect"
- similar to **Case #1**

Scenario #3 - NRC concludes substantial number should have been "defect"
- similar to **Case #2**

Case #4

Licensee left in service tubes with defects. Licensee asserted that the defects were within the TS limits. The NRC position was that the licensee was not correct. The licensee noted that there was no proof or even evidence that the tubes had been beyond TS limits. Specifically, the licensee plugged many tubes in a current outage and many of the tubes had been left in service two outages ago with defects that were concluded not to exceed TS limits (i.e., not greater than the 40% through wall TS limit). The tubes were not reinspected during the next outage and during the current outage were found well beyond the TS limit (e.g., 80%). The NRC position: it was a virtual certainty that most, if not all, the tubes affected were beyond the TS limit during the previous outage (but were not inspected) and were therefore left in service in violation of the TS.

Conclusion:
- A violation occurred, based on the preponderance of the evidence
- Each affected tube could represent a SLIV
- See Zion case, EA 95-118, NUREG-0940, Volume 14, Nos 3 and 4

Case #5

A facility licensee was determined to be performing little monitoring for SG tube leakage. The unit TS contained a limit of 150 gpd for SG leakage and the licensee monitoring measures were adequate to detect that the TS limit was met. NRC and industry notifications had occurred concerning SG tube leakage that showed that leaks above 50 gpd could rapidly grow to gross failure. The current technology in use at other sites could detect leakage as low as 20 gpd. The licensee had taken no additional actions after the notifications. Actual SG leakage was confirmed to be below 150 gpd. No TS violation occurred.

Conclusion - under Appendix B:

- Possible violation of requirement to review events or notifications
- The requirement comes from NUREG-0737 (imposed by Order), I.C.5, as used in EA 91-182 (NUREG-0940, Vol 11, No. 1, page I.A-1)

Case #6

During operation, a facility experienced a major SG tube rupture event. The licensee stabilized the plant and went to cold shutdown to effect repairs. NRC inspection of the event also looked into the cause of the SG tube rupture, including review of the SG tube assessment practices and data from the previous outages.

Conclusion - if no assessment problem found (e.g., unexpected loose part):
- No violation

Conclusion - if assessment deficiencies determined to be root cause:
- Potential Severity Level I violation, especially if substantial offsite releases occurred (though such releases are not a prerequisite)
- Potential Severity Level III or II violation, if extent of event is considered not to merit a Severity Level I violation.

Probabilistic Safety Assessment Calculation / Analysis Summary Sheet		Calculation / Analysis No. PSA-000717-1	Revision No. 0
Preparer: D. Gaynor P. Guymer (HRA)	Date:	Reviewer: M. Xing	Date:
Subject / Title Application of SGTR Sequences From PSA Baseline Model to 2/15/00 Event			

Purpose:

To determine the potential for core damage under the conditions present during the 2/15/00 steam generator tube failure event

Method / Assumptions:

BACKGROUND

The Steam Generator Tube Rupture (SGTR) initiating event is generally modeled as a double ended failure of a single tube in one steam generator. Dominant contributors to core damage frequency associated with such a SGTR event as modeled are:

a) Failure to isolate and depressurize the ruptured SG, leading to eventual depletion of the RWST.
b) Failure to maintain flow to the core due to failure of the injection system
c) Failure to maintain decay heat removal (by AFW or bleed and feed)

SGTR plant damage states are generally separated into those involving a stuck open safety valve and those with successful re-closure of the safety valve. For full STGR events, those sequences leading to core damage and involving stuck open safety valves are normally considered to be large early releases. Those sequences in which the safety valves successfully re-close will result in much lower (and later) source term releases and there is no clear industry position regarding the appropriate binning of these sequences with respect to LERF. The contribution of these two core damage states to total CDF for the IP2 baseline model is 1.35 E-7 per year for the sequences with stuck open valves and 8.7 E-7 for sequences in which the safety valve successfully re-closes. The total contribution of sequences associated with a SGTR initiating event as modeled is the sum of these two end states. The initiating event frequency for such steam generator tube ruptures is 1.3E-2/yr. Given the occurrence of a full double ended steam generator rupture, this would therefore yield a conditional core damage probability of (8.7 E-7 + 1.35 E-7) / 1.3 E-2 = 7.73 E-5.

2/15/00 EVENT SPECIFIC EVALUATION

Comparison to LERF Definition

For this event, the actual maximum flow rate out of the tube was 109 gpm (91 gpm following the reactor trip), a small fraction of the flow from a full SGTR. Given 345,000 gallons in the RWST, at this flow rate even without makeup to the RWST or any other recovery action, depletion of the RWST would not occur for more than two days (345,000 / (109 x 60) = 52 hours) after the event. This assumes that the flow rate does not decrease over time, which would be expected. Even in a worst case scenario of SI pumps injecting at their cutoff head and the ruptured steam generator depressurized due to a stuck open valve, the differential pressure across the tubes would be similar to the differential pressure that was present prior to the reactor trip and therefore the time available would also be similar. Again this assumes a constant flow rate throughout the event which is a bounding condition. Even with this bounding condition, there would be ample time to effectively evacuate the local population and therefore this would not constitute a Large Early Release as described in Appendix H of Inspection Manual, Chapter 0609.

Furthermore, given the actual primary to secondary flow rate in this event, the use of primary water to make up to the RWST could be effective in substantially extending the time to depletion of the RWST inventory in all applicable sequences. The potential for this mode to continue indefinitely, in essence represents a quasi-stable state.

Attachment 7

Probabilistic Safety Assessment Calculation / Analysis Summary Sheet	Calculation / Analysis No. PSA-000717-1	Revision No. 0

Application of Specific Steam Generator Tube Rupture Sequences to this Event

Operator Actions

The dominant cutsets associated with failure to isolate and depressurize the ruptured SG are driven by operator action. The additional time available increases the likelihood that the operators will be successful in taking the EOP directed mitigating actions and even allows substantial time for alternate actions to be taken. This extended time window for success would be expected to substantially lower the human error rates, thereby reducing the frequency of those core damage sequences which are driven by operator error. The important operator actions for SGTR events were re-evaluated using the extended time available. The impact on specific operator actions are provided in Appendix 1.

Equipment Availability and Recovery

Many of the cutsets associated with sequences which are not driven by operator action involve failure of the secondary side valves needed to accomplish primary system cooldown and depressurization. Should the preferred set of valves fail to open, however, there is the potential for using a second, separate set of valves. Given the additional time available in this event, due to the low primary to secondary flow rate, this is a reasonable alternate success path. The EOPs also make reference to use of the turbine driven AFP steam exhaust as a backup means for dumping steam.

Ability to Maintain Injection Flow to the Core

The use of the charging pumps is not credited as a successful path for maintaining injection flow to the core, given the flow rates associated with full SGTR initiating events. For this event, however, the charging pumps could have provided sufficient core injection flow to preclude core damage even in the event of a failure of the high pressure emergency core cooling injection system.

Decay Heat Removal (by AFW or bleed and feed)

These sequences are not substantially impacted by the smaller flow rate associated with this event since they are in response to a loss of decay heat removal rather than maintaining the core covered. The actions required for this function must still be performed within essentially the same timeframe.

Shutdown Cooling Mode

There is an assumption that shutdown cooling will eventually be required for sequences where steam generator isolation is not achieved. These sequences in the baseline model include successful depressurization (Top Event OS) and RWST makeup (Top Event MU) following failure to isolate the ruptured generator (OS and SO) and are binned to PDS48A on the basis of the failure to isolate the Steam Generator. For the purpose of this event specific evaluation, however, the success of depressurization would substantially extend the time at which one needs to successfully initiate the shutdown cooling mode, possibly indefinitely, but certainly long enough to allow time for recovery from hardware failures that drive failure of the shutdown cooling top event.

Results:

Table 1 describes the split fractions contained in the dominant SGTR core damage sequences and the additional credit that is being applied to recognize the impact of the actual tube leakage condition associated with the 2/15/00 event.

Table 2 provides the impact on each dominant sequence down to 1E-7. The table also provides the impact if the reduction found were applied to the remaining sequences.

Attachment 7

Probabilistic Safety Assessment Calculation / Analysis Summary Sheet	Calculation / Analysis No. PSA-000717-1	Revision No. 0

If we only account for the impact on the sequences specifically reevaluated (i.e. those with initial frequencies greater than or equal to 1E-7), the revised conditional SGTR core damage frequency is 4.77 E-6. Assuming that a similar reduction would be achieved for the rest of the sequences, the core damage frequency would be further reduced to 2.20 E-6.

Conclusions:

Compared to the modeled Steam Generator Tube Rupture, the event on 2/15/00 involved a substantial less severe challenge and provided additional time for correct implementation of procedure directed actions, recovery of equipment and use of alternate mitigating equipment or actions. As a result, the potential for the event leading to a core damage event and a large early release of source term is reduced. The results of this analysis show that reduction to be more than an order of magnitude less than a "classic" steam generator tube rupture event.

References:

Attachment 7

Probabilistic Safety Assessment Calculation / Analysis Summary Sheet	Calculation / Analysis No. PSA-000717-1	Revision No. 0

Calculation/Analysis:

The important operator actions for SGTR events were re-evaluated using the extended time available. The impact on specific operator actions are provided in Appendix 1.

Table 1 describes the split fractions contained in the dominant SGTR core damage sequences and the additional credit that is being applied to recognize the impact of the actual tube leakage condition associated with the 2/15/00 event.

Table 2 shows the top 100 SGTR sequences. It should be noted that the sequences are shown in groups of two with the only difference being the inclusion of a SWS1 split fraction. This split fraction is required to properly reflect the fact that IP2 has two separate service water headers, either of which could be aligned to the essential or non essential header at a given time. The two sequences therefore represent identical scenarios with either plant configuration.

For each sequence with a frequency greater than or equal to 1E-7, the table provides:

- the baseline CDF contribution
- the conditional CDF contribution given the event has occurred
- the failed split fractions associated with each sequences
- the intermediate split fraction for any split fraction modeled as conditional upon an earlier top event
- the split fraction adjustments made (based on the discussion in Table 1 and the results of Tables 3 through 5)
- the overall sequence reduction factor corresponding to the split fraction changes
- the revised sequence contribution to CDF

For the remaining sequences (i.e. <1 E-7 but still within the top 100 sequences), the table does not evaluate each specific sequence, but provides the overall change in CDF for two cases:

1) assuming no impact on the remaining sequences, and
2) assuming the reduction found for the sequences above 1E-7 was typical and could be applied to the remaining sequences

Attachment 7