PMComanchePeakPEm Resource

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Subject: 2010-11-17 Draft Material to further Discussion re TS Methodology to support RITS
Attachments: 2010-11-11 Technical Specification Methodology Draft 0.doc; 2010-11-15 Tanaka-san initial assessment of NEI 06-09 applicability to new plants.docx; 2010-11-12 Tasks.doc; NEI 06-09RMTS_markup(11162010).pdf; NEI 04-10 R1_RITS5b_markup(11162010).pdf

Steve,

Attached are the documents that I mentioned this morning. They are rough drafts but I believe they can serve as a basis for further dialog with the NRC. If possible we would like a public meeting on 11/30 or 12/1 to continue our discussions. Please let me know if either date will work for the staff.

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Hearing Identifier: ComanchePeak_COL_Public
Email Number: 1166

Mail Envelope Properties (A34507C196705B44B7F8F0B1BFE80AAE074F269AFA)

Subject: 2010-11-17 Draft Material to further Discussion re TS Methodology to support RITS
Sent Date: 11/17/2010 2:54:14 PM
Received Date: 11/17/2010 2:53:38 PM
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Files	**Size**	**Date & Time**
MESSAGE	967	11/17/2010 2:53:38 PM
2010-11-11 Technical Specification Methodology Draft 0.doc	55872	
2010-11-15 Tanaka-san initial assessment of NEI 06-09 applicability to new plants.docx	37813	
2010-11-12 Tasks.doc	40000	
NEI 06-09RMTS_markup(11162010).pdf	811557	
NEI 04-10 R1_RITS5b_markup(11162010).pdf	500420	

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

Technical Specification Methodology

for

Configuration Risk Management Program (CRMP)

and

Surveillance Frequency control Program (SFCP)

for

Comanche Peak Nuclear Power Plant Units 3 and 4

Draft
November 11, 2010

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1.0 Introduction

This methodology addresses how the Configuration Risk Management Program (CRMP) and the Surveillance Frequency Control Program (SFCP) are implemented per Comanche Peak Nuclear Power Plant (CPNPP) Units 3 and 4 Technical Specifications (TS), 5.5.18 and 5.5.19 respectively.

As noted in these two specifications, actions are to be taken in accordance with the applicable NEI documents – NEI 06-09 (Revision y) for CRMP and NEI 04-10 (Revision z) for SFCP. Both of these documents were originally written for plants with an operating license and with a Probability Risk Assessment (PRA) that which was already reviewed and accepted by the NRC prior to approval of the TS programs. Section 2.0 of this methodology incorporates the NEI documents and provides the changes needed to make the documents applicable to CPNPP Units 3 and 4. Section 3.0 addresses the technical adequacy of the PRA to support these programs.

This report applies to CPNPP Units 3 and 4 from issuance of the COL through construction and including operation of the units.

2.0 Incorporation of NEI Documents

TS 5.5.18 and 5.5.19 adopt NEI 06-09 and NEI 04-10. These NEI documents address many aspects of the CRMP and SFCP. In order to fully implement the documents, they are incorporated into the Technical Specification Methodology for CPNPP Units 3 and 4 with the modifications needed to make them fully applicable to these plants. The full incorporation is addressed in sections 2.1 and 2.2.

2.1 NEI 06-09, Revision y, "Risk-Managed Technical Specifications (RMTS) Guidelines"

NEI 06-09, Revision y, "Risk-Managed Technical Specifications (RMTS) Guidelines" is hereby incorporated into this methodology report with the following revisions.

[Identify the portions of NEI 06-09 to be deleted, revised or supplemented.]

2.2 NEI 04-10, Revision z, "Risk-Informed Method for Control of Surveillance Frequencies"

NEI 04-10, Revision z, "Risk-Informed Method for Control of Surveillance Frequencies" is hereby incorporated into this methodology report with the following revisions.

[Identify the portions of NEI 06-09 to be deleted, revised or supplemented.]

3.0 PRA Model

Both the CRMP and the SFCP are supported by appropriate PRA models. The PRA models are described in sufficient detail to allow issuance of the COLs for CPNPP Units 3 and 4 and to allow continued implementation of these programs during operations.

Numerous documents are used to describe the PRA models being used. The three primary documents are US NRC Regulatory Guide 1.200 revision x and NEI 06-09 and NEI 04-10 as incorporated in section 2.0 above.

[This is where we need to start getting specific about the PRA. It will probably need to address some of the standards we will follow and cover how some requirements, such as the peer review, operating experience, will be completed.]

4.0 Risk Metrics

One aspect of these programs was uncertain when Luminant applied for COLs for CPNPP Units 3 and 4. This aspect was the risk metrics to be applied. Risk Metrics are the values for various risk parameters used to make decisions. The risk metrics contained in several regulatory guides (e.g., RG 1.174 and RG 1.177). The thresholds and limits in such guidance is based upon the base risk associated with the nuclear plants which were operating at the time. The new plants applying for licenses at the same time frame as CPNPP Units 3 and 4 have base risk values lower (as much as several decades) than the operating plants. Studies were performed to determine how to ensure that risk metrics did not eroded the enhanced safety of the new plants while not creating an dis-incentive to design safer plants.

Luminant addressed this issue by [insert our path forward – adopt bounding values, wait for NRC to decide, etc.]

NEI 06-09 describes 1) applicability of RMTS to each plant operational modes, 2) RMTS thresholds, and 3) RMTS Program Requirements. Applicability of the each item is discussed below.

1. Applicability of RMTS to plant operational Modes

The applicability to each plant operational Modes is described in the NEI guideline as show in table 2-1. US-APWR design is basically the same with conventional PWRs and the discussion in the NEI guideline is applicable to US-APWR. Further discussion on the applicability of RMTS to plant operation mode 3 in the US-APWR is provided in response to RAI #XXX [*will be checked later*] of the US-APWR DCD.

Table 2-1
Applicability of At-Power PRA for RMTS to Plant Operational Modes. Note: Mode numbers are in accordance with Improved Technical Specification definitions.

Applicability of At-Power PRA to RMTS	PWR	BWR
Direct Application	1, 2,	1, 2,
Plant Specific Applicability*	3, 4*	3*
Not Applicable	4*, 5, 6	3*, 4, 5

2. RMTS Thresholds

The risk management thresholds described in NEI 06-09 is determined with consideration of NUMARC 93-01. It is also stated in the NEI guideline as;

"These thresholds are deemed appropriate for RMTS programs because they relate to integrated plant risk impacts that are occasional and temporary in nature (versus permanent) and are consistent with Reference guidance *[R.G. 1.174 r1]* that has been previously endorsed by the NRC.".

In the June 3 (2010) public meeting "Public meeting on the status of risk informed regulatory guidance for new reactors", NRC staff stated the applicability of NUMARC 93-01 section 11.3.7.2 to new plants as follows:
"

- Theoretically, this quantitative guidance if applied to some new reactors could allow normal work controls for ICDP of high 10^{-7} which would represent a significant fraction of or even several years' worth of integrated risk for baseline CDF of 10^{-7} to 10^{-6} /yr
- Staff exercised SPAR models for one plant and did find that technical specifications AOTs and investment protection short-term availability controls limited the ICDPs to reasonably low values for maintenance of key equipment for those cases evaluated "

The 30 day back-stop may provide a reasonable control to limit the ICDPs to a reasonable value. However, RMTS thresholds described in NEI 06-09 needs to be revisited and modified as necessary when the risk-informed regulatory guidance for new reactors is published. The NEI guideline needs to be supplemented.

Need to consider options that can be taken to modify for this item

-Show that the 30 day-stop controls the ICDPs to be reasonably low values using the current PRA model

-Consider lower thresholds

- other?

3. RMTS Program Requirements

Requirements applicable to the activities necessary for RMTS implementation are provided in Chapter 2 of NEI 06-09. The requirements are the followings.

- ✓ Configuration Risk Management Process & Application of Technical Specifications
- ✓ Documentation
- ✓ Training
- ✓ PRA Technical Adequacy
- ✓ Configuration Risk Management Tools

Applicability of the above requirements to new plants is summarized in the tables 1 and 2.

Table 1 Applicability of RMTS programs requirements of NEI 06-09 to US-APWR

RMTS Program Requirements (NEI 06-09)	Applicability to new plants
Configuration Risk Management Process & Application of Technical Specifications	Applicable with exception. This requirement is not affected by plant design or the availability of design and operational information. The only exception is the risk criteria.
Documentation	Applicable. This requirement is not affected by plant design or the availability of design and operational information.
Training	Applicable to US-APWR. This requirement is not affected by plant design or the availability of design and operational information.
PRA Technical Adequacy	Applicable with exception. See table for detail
Configuration Risk Management Tools	Applicable. This requirement is not affected by plant design or the availability of design and operational information.

Table 2 PRA Technical adequacy requirements of NEI 06-09 to US-APWR

	PRA Technical Adequacy for RMTS (NEI 06-09)	Applicability to new plants	Notes
1	Modeling of removal of plant SSCs from service	Applicable	
2	Compliance with R.G. 1.200 r0 and Capability Category 2 of ASME PRA std.	Not applicable	10CFR50.71 (h)(1) ensures this requirement to be met by initial fuel load
3	Evaluation of CDF and LERF Assessment of external events	Applicable	
4	Capability to quantify configuration specific impact due to unavailability of equipments in CRM program	Applicable	
5	Consideration of current (i.e. Seasonal or time of cycle) configuration	Applicable	Conservative assumption at all time is acceptable
6	Common cause treatment in CRM model	Applicable	
7	Maintain and update PRA	Applicable after plant operation	10CFR50.71 (h)(1) ensures the PRA reflects as-built information at initial fuel load
8	Satisfy software station software quality assurance requirements	Applicable	
9	Arguments on use of at-power PRA to low operating modes	Applicable	
10	Consideration of modeling uncertainty in the RMTS program	Applicable with supplementary requirements specific to new plants	Need to consider additional effort to address uncertainty that stem from unavailability of plant specific data and operational experience.

Task- **Develop a TS methodology and a PRA methodology for new plants that the NRC can approve pre-COL**

Approach

<u>TS methodology</u>

- Request OGC to revisit "if and only if" statements
- Mark up NEI 09-06 to apply to new plants
  - Submit an "Exceptions Paper" showing how we would meet the revised requirements
- Mark up NEI 04-10 to apply to new plants
  - Submit an "Exceptions Paper" showing how we would meet the revised requirements
- Develop OE for GTGs
- Develop a Configuration Risk Management Program (CRMP)
- Develop a Surveillance Frequency Control Program (SFCP)
- Develop acceptable risk metrics (or wait for Commissioners' decision about which option in SECY 10-0121)
  - Mark up RG 1.174 to apply to new plants
    - Submit an "Exceptions Paper" showing how we would meet the revised requirements
  - Mark up RG 1.177 to apply to new plants
    - Submit an "Exceptions Paper" showing how we would meet the revised requirements

<u>PRA methodology</u>

- List the requirements from 10 CFR 50.71(h)(1)
  - Figure out how to meet each requirement with what we have
- Mark up NEI 09-06 to apply to new plants
- Mark up NEI 04-10 to apply to ne w plants
- Mark up RG 1.200 to apply to new plants

NEI 06-09 (Revision 0)

Risk-Informed Technical Specifications Initiative 4b

Risk-Managed Technical Specifications (RMTS) Guidelines

Industry Guidance Document

November 2006

ACKNOWLEDGMENTS

This document was originally developed by EPRI as:

Risk-Managed Technical Specifications (RMTS) Guidelines

EPRI Report 1013495

The development of the requirements for Risk-Managed Technical Specifications was supported by the RITS 4B development team. NEI wishes to acknowledge the efforts of the following individuals who contributed to this effort:

Steve Hess	Electric Power Research Institute
John Gaertner	Electric Power Research Institute
Ray Schneider	Westinghouse
Gary Chung	Southern California Edison
Rick Grantom	South Texas Project Nuclear Operating Company
Alan Hackerott	Omaha Public Power District
Wayne Harrison	South Texas Project Nuclear Operating Company
Scott Head	South Texas Project Nuclear Operating Company
Dave Musick	South Texas Project Nuclear Operating Company

EXECUTIVE SUMMARY

This document provides guidance for implementation of a generic Technical Specifications improvement that establishes a risk management approach for voluntary extensions of completion times for certain Limiting Conditions for Operation. This document provides the risk management methodology, which will be approved through an NRC safety evaluation, and will be referenced through a paragraph added to the Administrative Controls section.

This methodology uses a risk-informed approach for establishment of extended completion times, and is consistent with the philosophy of NRC Regulatory Guide 1.174. Probabilistic Risk Assessment (PRA) methods are used to determine the risk impact of the revised completion times. PRA technical adequacy is addressed through NRC Regulatory Guide 1.200, which references the ASME PRA standard, RA-S-2005b for internal events at power. Quantification of risk due to internal fire and other significant external events is also necessary for this application, through PRA or bounding methods.

Section 2.0 of the document provides requirements for implementation. Section 3.0 provides additional implementation guidance relative to these requirements. Section 4.0 presents attributes of the PRA and configuration risk assessment tools. The extension of completion time must take into account the configuration-specific risk, and is an extension of the methods used to comply with paragraph (a)(4) of the maintenance rule, 10 CFR 50.65. Plants implementing this initiative are expected to use the same PRA analyses to support their maintenance rule (a)(4) programs. A deterministic backstop value is imposed to limit the completion time extension regardless of low risk impact. Results of implementation are monitored, and cumulative risk impacts are compared to specific risk criteria. Corrective actions are implemented should these criteria be exceeded.

Report Development History

This report presents nuclear utilities with a framework and associated general guidance for implementing Risk Managed Technical Specifications (RMTS) as a partial replacement of existing Technical Specifications. This report was initially prepared for EPRI with extensive technical input and review by the Nuclear Energy Institute (NEI) Risk-Informed Technical Specifications Task Force (RITSTF), which includes input from the PWR Owner's Group. This report is a substantial Technical Update to EPRI Report 1011758, which was published in December 2005. A draft of the revision provided in this report was submitted to the Nuclear Regulatory Commission (NRC) staff to support pilot applications of RITSTF Initiative 4B. This revision incorporates modifications to address comments provided by NRC staff and is intended for use by plants implementing the RITS Initiative 4B application.

Background

Since 1995, the methodology for applying PRAs to risk-informed regulation has been advanced by the publication of many reports. Related to the area of Risk-Informed Technical Specifications alone, EPRI has published the *PSA Applications Guide* (TR-105396), *Guidelines for Preparing Risk-Based Technical Specifications Change Request Submittals* (TR-105867), *Risk-Informed Integrated Safety Management Specifications (RIISMS) Implementation Guide* (1003116), and *Risk-Informed Configuration-Based Technical Specifications (RICBTS) Implementation Guide* (1007321). NRC has issued Regulatory Guide 1.177 and a Standard Review Plan providing guidance on Risk-Informed Technical Specifications. Over the past four years, the NEI RITSTF has addressed several generic initiatives to further risk-inform station Technical Specifications. One of these, Initiative 4B, entitled Risk-Managed Technical Specifications, is the subject of this report. As of August 2006, two pilot implementations of Initiative 4B have been submitted by utilities to NRC for their approval with a third plant indicating its intention to also participate as a pilot plant. An earlier version of this report, EPRI Report 1002965 was submitted to NRC in support of these pilot submittals. Based on NRC reviews, EPRI Report 1009474 was produced and docketed with NRC. This report is a further revision based on NRC review, industry and NRC workshops on the subject, and industry experience using the guidelines.

Objectives

- To provide utilities with an approach for developing and implementing nuclear power station Risk-Managed Technical Specifications programs.
- To complement and supplement existing successful Configuration Risk Management applications such as the Maintenance Rule.
- To serve as NRC-approved guidelines for widespread implementation of RITSTF Initiative 4B.

Approach

Starting with available industry and NRC documentation, experienced PRA practitioners, acting through the NEI RITSTF, developed an approach and methodology for implementing Risk-Informed Technical Specifications. The method uses the guidance developed for the Maintenance Rule, 10CFR50.65 (a)(4), in Section 11 of NEI document NUMARC 93-01 as a starting point. The approach described in this report is a logical extension of that guidance to address the additional challenges of Risk-Managed Technical Specifications. The primary additions to the (a)(4) processes are 1) the calculation of a flexible risk-informed completion time (RICT) as an alternative to the static Allowed Out-of-service Times in current Technical Specifications, and 2) calculation of cumulative risk incurred through the use of these RICTs. Other extensions of the (a)(4) process are associated with the elevation of the process to a higher regulatory significance through its incorporation into Technical Specifications. This report provides the culmination of the RITS 4B initiative and serves as the industry implementation guidance for application of Risk Managed Technical Specifications.

Results

This report presents a recommended approach and technical framework for an effective RMTS program and its implementation following NRC approval. This report also provides, together with the industry consensus standards on PRA as modified by experience with NRC Regulatory Guide 1.200, the requirements for PRA scope and capability for this RMTS application.

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1 INTRODUCTION

The purpose of this report is to provide specific guidance on how to implement Risk-Managed Technical Specifications (RMTS) programs at existing and planned nuclear power stations using configuration risk management tools and techniques. It is a direct derivative of previous EPRI work, in particular EPRI Report 1011758 [1]. This report provides guidance for stations desiring to implement RMTS for a single system as well as those desiring to implement a global "whole plant" RMTS approach. This report is organized and presented as follows:

- Section 1 is an overview of the history preceding RMTS programs.
- Section 2 provides the RMTS program requirements.
- Section 3 presents detailed RMTS guidance approach and methodology.
- Section 4 presents the attributes of a PRA and associated Configuration Risk Management (CRM) Tools that are required for RMTS implementation.
- Section 5 presents RMTS references.
- Appendix A provides a glossary of terms.

10CFR50.36, "Technical Specifications," requires that each specification contain a Limiting Condition for Operation (LCO). The LCO is the minimum functional capability or performance level of equipment required for safe operation of the facility. When an LCO is not met, 10 CFR 50.36 requires the licensee to shut down the reactor or follow any remedial action permitted by the Technical Specifications until the condition can be met. No specific timing requirements were included in the regulation. However, in practice, each specification contains actions to follow when the LCO is not met and these actions are associated with one or more fixed time limit. Within the context of the plant Technical Specifications, these time limits are termed the Allowed Outage Times (AOTs) or Completion Times (CTs). These time limits were established at the time of station licensing or in subsequent license amendments. In this document, the term completion time (CT) refers to completion time and/or allowed outage time.

The nuclear industry has applied risk-informed techniques to extend various CTs originally established in the Technical Specifications. The RMTS described in this report builds on that experience to establish a process to apply configuration risk management to enable a licensee to vary the CT in accordance with the risk calculated for the plant configuration.

This guideline is applicable to risk informing the Technical Specifications CTs for plant configurations in which structures, systems, and components (SSCs) are inoperable. The primary use of this guidance is anticipated to be for configurations (either preplanned or emergent) that occur during the conduct of maintenance. It is expected that implementation of RMTS will allow utilities to more fully utilize risk-informed tools and processes in the management of maintenance. These Technical Specifications enhancements will reduce plant risk by allowing flexibility in prioritizing maintenance activities, improving resource allocation, and avoiding unnecessary plant mode changes. The RMTS under development are specifically directed toward equipment outages and will not change the manner in which plant design parameters are controlled.

This guide supplements Nuclear Energy Institute (NEI) guidance for implementation of the Maintenance Rule (see Section 11 of Reference [2]) for stations implementing RMTS. Additional key references include EPRI's PSA Applications Guide [3] and NRC's Regulatory Guide 1.174 [4]. Maintenance activities are performed to ensure the level of equipment reliability necessary for safety, and should be carefully managed to achieve a balance between the benefits and potential impacts on safety, reliability, and availability. The benefits of well managed maintenance conducted during power operations include increased system and unit availability, reduced equipment and system deficiencies that could impact operations, more focused attention on safety due to fewer activities competing for specialized resources, and reduced work scope during outages.

This report is a key part of the NEI Risk Informed Technical Specifications Task Force (RITSTF) initiatives. RMTS is designed to be consistent with, and provide enhancement to, the guidance provided for Maintenance Rule risk management described in Reference [2]. The guidance contained in this report is applicable to the determination of risk-informed completion times (RICTs), Risk Management Action Times (RMATs) (reference Appendix A for definitions of these terms) and specification of appropriate compensatory risk management actions (RMAs) applicable to requirements of the Technical Specifications. In application of this guidance to maintenance activities on plant SSCs governed by Technical Specifications, both the provisions of the RMTS and the requirements specified under the provisions of Maintenance Rule section (a)(4) are applicable. This section summarizes the enhancements that this initiative brings to prudent safety management.

It is not the intent of the RITSTF initiatives to modify the manner in which the Maintenance Rule requirements are met by various utilities. However, it is the intent of this report to provide the guidance for integrating Risk-Managed Technical Specifications with the Maintenance Rule process. While the fundamental process to be used for the RMTS is not different from the Maintenance Rule process, the proposed risk assessment process has an increased quantitative focus and requires a more formal mechanism for dispositioning configuration management decisions.

RMTS features balance the flexibility in performing maintenance within a structured risk informed framework so as to adequately control the risk impact of maintenance decisions.

The RMTS process discussed in this report may be used within the current configuration risk management program that implements the Maintenance Rule (a)(4) requirements. Specifically, this report describes integration of the present 10CFR50.65(a)(4) evaluation process with selected supplementary processes to create an enhanced process that will support the implementation of flexible CTs within the Technical Specifications. However, there is a fundamental difference between the two programs. RMTS is specifically applicable to Technical Specification operability of SSCs, while the provisions of Maintenance Rule section (a)(4) are concerned with functionality of a broader scope of SSCs. Due to this fundamental difference, the provisions of both programs are applicable and must be performed during applications of RMTS.

The RMTS process is intended to provide a comprehensive risk informed mechanism for expeditious identification of risk significant plant configurations. This will include implementation of appropriate compensatory risk management actions, while retaining the current Technical Specifications action statement requirements, including the action to shut down the plant when prudent. In practice, this program is consistent with 10CFR50.65(a)(4) maintenance planning conditions. That is, the program retains the current 10CFR50.65(a)(4) thresholds for identifying normal and high risk plant configurations. The processes described herein provide additional requirements to those required by the Maintenance Rule (a)(4) In addition, the revised process ensures timely risk assessments of emergent (unscheduled) plant configurations to ensure that high-risk conditions associated with multiple component outages are identified early. This document also includes guidance on the scope and quality of the risk-informed tools used in performing the configuration risk assessments.

2
RMTS PROGRAM REQUIREMENTS

This Section delineates the requirements for RMTS applications. In this chapter, the conditions under which the RMTS program is applicable are defined. Then, requirements applicable to the activities necessary for RMTS implementation are provided. These activities are comprised of the following:

- Configuration risk management process and application to Technical Specification requirements.
- Documentation requirements.
- Training requirements.
- PRA technical adequacy requirements.
- Configuration risk management tool requirements.

Information associated with the purpose and details associated with the implementation of the individual RMTS requirements are provided in Chapters 3 and 4. Chapter 3 provides detailed guidance on the RMTS programmatic requirements and the conduct of activities necessary to implement the RMTS program. Chapter 4 provides information associated with the PRA and configuration risk management models and tools used in the RMTS program.

2.1 Applicability

A RMTS program is designed to apply the risk insights and results obtained from a plant PRA to identify appropriate Technical Specifications CTs and appropriate compensatory risk management actions associated with plant SSCs that are inoperable. A RMTS program defines the scope of equipment used to define plant configurations to which calculation of a risk-informed completion time (RICT) may be applied. These SSCs have front-stop CT requirements, and can be evaluated via the RMTS-supporting PRA and CRM program. Technical Specifications for Safety Limits, Reactivity Control, Power Distribution, and Test Exceptions are excluded from utilizing RICTs.

PRAs that support RMTS are typically plant specific at-power PRAs. Thus, these PRA's are directly applicable to plant configurations during operation in Modes 1 and 2. For PWRs, RMTS may be extended on a plant-specific basis to apply in operating Modes 3 and 4 (with cooling via steam generators) while for BWRs it may be extended to Mode 3 (with cooling via main condenser). However, licensees who want to apply RMTS for plant configurations in these other operating modes shall either have a PRA and configuration risk calculation tool that adequately calculates a RICT in these modes for the specific plant configurations or perform sufficient analyses to demonstrate that the at-power PRA results provide conservative bounding estimates of risk, and thus can be used to set the RICT. Applicability to these modes must be justified as part of the license application, and approved by NRC. Also, the station configuration risk management (CRM) program (see definition in Appendix A) shall establish the program-specific requirements for application of an at-power PRA to non-power operating modes. Technical Specifications associated with the Cold Shutdown and Refueling modes are not within the scope of this guidance. Table 2-1 provides the applicability of the RMTS program during various operating modes.

Table 2-1
Applicability of At-Power PRA for RMTS to Plant Operational Modes. Note: Mode numbers are in accordance with Improved Technical Specification definitions.

Applicability of At-Power PRA to RMTS	PWR	BWR
Direct Application	1, 2,	1, 2,
Plant Specific Applicability*	3, 4*	3*
Not Applicable	4*, 5, 6	3*, 4, 5

* RMTS is applicable to PWR Modes 3 and 4 for cooling via steam generators or BWR Mode 3 for cooling via main condenser, when justified and approved by NRC as part of the plant specific application; RMTS is NOT applicable to PWR Mode 4 or BWR Mode 3 for cooling via shutdown cooling.

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2.2 RMTS Thresholds

Risk management thresholds for RMTS program application are established quantitatively by considering the magnitude of the instantaneous core damage frequency (CDF), instantaneous large early release frequency (LERF), incremental core damage probability (ICDP), and the incremental large early release probability (ILERP) for the plant configuration of interest. The risk management thresholds presented in Table 2-2 are the basis for RMTS program action requirements.

Table 2-2
RMTS Quantitative Risk Management Thresholds

Criterion*		RMTS Risk Management Guidance
CDF	LERF	
≥10^{-3} events/year	≥10^{-4} events/year	- Voluntary entrance into configuration prohibited. If in configuration due to emergent event, implement appropriate risk management actions.
ICDP	ILERP	
≥10^{-5}	≥10^{-6}	- Follow the Technical Specification requirements for required action not met.
≥ 10^{-6}	≥ 10^{-7}	– RMAT and RICT requirements apply – Assess non-quantifiable factors – Implement compensatory risk management actions
<10^{-6}	<10^{-7}	– Normal work controls

* In application of these RMTS criteria, the criteria for both columns apply simultaneously and actions are taken based on the more restrictive one.

2.3 RMTS Program Requirements

This section provides a concise listing of RMTS programmatic requirements. Detailed discussion of the configuration risk management and Technical Specification requirements applicable to RMTS are provided in Chapter 3. Chapter 4 provides a detailed discussion of requirements associated with the PRA models and CRM tools used in RMTS program implementation.

2.3.1 Configuration Risk Management Process & Application of Technical Specifications

Existing Technical Specifications for nuclear power stations specify completion times for completing actions when specific plant equipment is inoperable. Under the RMTS concept, these CT values are maintained and referred to as “front-stop”

CT values. In the RMTS program, operation beyond the front-stop CT is allowed provided the risk of continued operation can be shown to remain within established limits as determined by the CRM program and supported by the PRA.

The station's CRM program and RMTS process shall be performed in accordance with station procedures which include the following process requirements:

1. Risk assessments used in RMTS shall be performed in accordance with guidance provided in Sections 2 and 3 of this document and supported by the implementing plant's PRA and CRM program. Risk assessments involve computation of a Risk Management Action Time (RMAT) and a Risk Informed Completion Time (RICT)

    - The RMAT is the time interval at which the risk management action threshold is exceeded. It is the time from discovery of a condition requiring entry into a Technical Specifications action for a SSC with the provision to utilize a RICT until the 10^{-6} ICDP or 10^{-7} ILERP RMA threshold is reached, whichever is the shorter duration.

    - The RICT is a plant-specific SSC plant configuration CT calculated based on maintaining plant operation within allowed risk thresholds or limits and applying a formally approved configuration risk management program and associated probabilistic risk assessment. The RICT is the time interval from discovery of a condition requiring entry into a Technical Specifications action with the provision to utilize a RICT until the 10^{-5} ICDP or 10^{-6} ILERP threshold is reached, or 30 days, whichever is shorter. The maximum RICT of 30 days is referred to as the "back-stop CT." Note that each Technical Specification within the scope of RITS 4B has a front-stop and back-stop CT specifically applicable to it. However, the RICT is applicable to the plant configuration.

2. Risk Managed Technical Specifications are applied under the following conditions:

    2.1. To extend a CT beyond its front-stop CT.
    2.2. To evaluate configuration changes once a RICT is being used beyond the associated front-stop CT.

3. For plant configurations in which the RMAT either has been exceeded (emergent event) or is anticipated to be exceeded (either planned condition or emergent event), appropriate compensatory risk management actions shall be identified and implemented. For preplanned maintenance activities for which a RICT will be entered, RMAs shall be implemented at the earliest appropriate time.

4. Upon implementation of the RMTS program for an inoperable SSC within the program scope, prior to exceeding the RMTS front-stop CT the station shall perform a risk calculation to determine the applicable risk management action time (RMAT) and risk- informed completion time (RICT).

5. When a system within the scope of the RMTS program is in a RICT (i.e., when it is Technical Specification inoperable and beyond its front-stop CT – see definition in Appendix A), and the functional / operable status of any subsequent SSC within the scope of the plant CRM program changes (i.e., a functional / operable SSC becomes non-functional / inoperable), the plant shall perform a risk calculation to determine a revised risk management action time (RMAT) and risk-informed completion time (RICT) applicable to the new plant configuration. This calculation shall be performed prior to exceeding the most limiting applicable Technical Specification front-stop CT (for SSCs governed by Technical Specifications) but not later than 12 hours from the plant configuration change. For plant configuration changes in which a non-functional / inoperable SSC is returned to service, the plant may perform a risk calculation to determine a revised risk management action time (RMAT) and risk-informed completion time (RICT).

    - The revised RICT from the evaluation shall be effective from the time of implementation of the original RICT for the original non-zero maintenance plant configuration.
    - In the RMTS framework, a RICT can be revised, occasionally many times, but the associated "time clock" cannot be re-set until all LCOs associated with front-stop CTs that have been exceeded have been met (i.e., are operable) or the applicability for the LCOs exited.

6. Should the RICT be reached the plant shall consider the required action to not be met and follow the applicable Technical Specification requirements, including any associated requirement for plant shutdown implementation.

7. RMAT and RICT calculations are performed in accordance with the following rules:

    - RMAT and RICT risk levels are referenced to Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) associated with the plant "zero-maintenance" configuration. The "zero-maintenance" state is established from the baseline PRA by assuming all components to be available (i.e., SSC unavailability and test and maintenance events are set to zero in the PRA model; train modeling is consistent with plant alignments).

- RMAT and RICT levels are referenced from the time of initial entry into the first RMTS and can only be reset once all RMTS action statements for SSCs beyond their front-stop CTs have been exited.
- The RMAT and RICT calculations may use conservative or bounding analyses.
- RMTS evaluations shall evaluate the instantaneous core damage frequency (CDF), instantaneous large early release frequency (LERF). If the SSC inoperability will be due to preplanned work, the configuration shall not be entered if the CDF is evaluated to be $\geq 10^{-3}$ events/year or the LERF is evaluated to be $\geq 10^{-4}$ events/year. If the SSC inoperability is due to an emergent event, if these limits are exceeded, the plant shall implement appropriate risk management actions to limit the extent and duration of the high risk configuration.
- Compensatory risk management actions may only be credited in the calculations to the extent they are modeled in the PRA and are proceduralized.
- The probability of repair of inoperable SSCs within the scope of the CRM program cannot be credited in the RMAT or RICT calculations.
- The impact of fire risks shall be included in RMAT and RICT calculations.
- The impact of other external events risks shall be addressed in the RMTS program. This may be accomplished via one of the following methods:

    A. Provide a reasonable technical argument (to be documented prior to implementation of the RMTS program) that the external events that are not modeled in the PRA are not significant contributors to configuration risk.

    B. Perform an analysis of the external event contribution to configuration risk (to be documented prior to implementation of the RMTS program) and incorporate these results in the RMTS program. This may be accomplished via performing a reasonable bounding analysis and applying it along with the internal events risk contribution in calculating the configuration risk and the associated RICT.

    C. Provide direct modeling of the external events in the PRA / CRMP plant model.

8. The RMTS completion time shall not exceed the back-stop CT limit of 30 days. This RMTS provision applies separately to each ACTION for which it is entered.

9. A RICT may not be applied for pre-planned activities when all trains of equipment required by the Technical Specification LCO would be inoperable.

10. For emergent conditions, a RICT may be applied when all trains of equipment required by the Technical Specification LCO would be inoperable, provided one or more of the trains are considered PRA functional as defined in item 11.

11. PRA Functionality Assessment Guidance

    An inoperable component shall be considered non-functional when performing the RICT calculation unless the provisions specified in 11.1 through 11.3 are met. If these provisions are met, the remaining function(s) of the system, subsystem, or train which are not affected by the condition which caused the SSC to be declared inoperable may be considered PRA functional when performing the RICT calculation.

    The following provides the requirements for conditions when PRA functionality may be applied to a SSC for the calculation of a RICT.

    11.1 If a component is declared inoperable due to degraded performance parameters, but the affected parameter does not and will not impact the success criteria of the PRA model, then the component may be considered PRA functional for purposes of the RICT calculation. For the provisions of this section to apply, the following must occur:

    11.1.1 The degraded condition must be identified and its associated impact to equipment functionality known.

    11.1.2 Further additional degradation that could impact PRA functionality is not expected during the RICT.

    11.2 If the functional impact of the condition causing the inoperability is capable of being assessed by the PRA model, then the remaining unaffected functions of the component may be considered PRA functional in the RICT calculation.

    11.3 If the function(s) affected by the condition causing a component to be inoperable is not modeled in the PRA, and the function has been evaluated and documented in the RMTS program as having no risk impact, then the RICT may be calculated assuming availability of the inoperable component and its associated system, subsystem or train. If there is no documented basis for exclusion, or if the condition was screened as low probability, then the inoperable component must be considered not functional.

    Note: Section 3.2.3 provides examples for application of PRA Functionality.

12. If a component within the scope of the CRM program is inoperable and PRA functionality cannot be quantified, then the component shall be considered non-functional for the RICT calculation. In any case where equipment declared as “inoperable” is being classified as “functional” for purposes of a RICT calculation, the reasoning behind such a consideration shall be justified in the documentation of the RICT assessment.

14. The as-occurred cumulative risk associated with the use of RMTS beyond the front-stop CT for equipment out of service shall be assessed and compared to the guidelines for small risk changes in Regulatory Guide 1.174 [4] and corrective actions applied as appropriate. This assessment shall be conducted every refueling cycle on a periodicity not to exceed 24 months.

15. Operability determinations should follow regulatory guidance established in Part 9900 of the NRC Inspection Manual [9]. RMAT and RICT calculations performed for emergent conditions shall be performed assuming that all equipment not declared inoperable during the operability determination process are functional. However, the station shall establish appropriate RMAs based on an assessment of the potential for increased risks due to common cause failure of similar equipment. (Note that if there is not evidence for increased potentiual for common cause failures, no RMAs are required).

2.3.2 Documentation

1. The CRM program process shall be documented in station procedures delineating appropriate responsibilities and related actions.

2. The process for conducting and using the results of the risk assessment in station decision-making shall be documented.

3. Procedures should specify the station functional organizations and personnel, including operations, engineering, work management and risk assessment (PRA) personnel, responsible for each action required for RMTS program implementation.

4. Procedures should clearly specify the process for conducting a RICT assessment and developing applicable RMAs.

5. Individual RMTS RICT evaluations shall:

   5.1. Be documented in an appropriate log**.**
   5.2. Document any quantified bounding assessments or other conservative quantitative approaches used.

5.3. In cases where equipment declared as inoperable is being credited as possessing PRA functionality for the purposes of a RICT calculation, the basis behind this determination shall be provided in the RICT documentation.

6. Relative to extended CTs beyond the front-stop CT, the following shall be documented:

6.1. The date/time an LCO(s) is not met requiring entry into a RICT.

6.2. The date/time for restoration of compliance with the LCO(s) or the exiting of the RICT.

6.3. If applicable, an assessment of PRA functionality based on the degree of SSC degradation.

6.4. The configuration specific risk (i.e., CDF and LERF) for the duration of extended CTs identifying inoperable equipment and associated plant alignments. This may include more than one CDF/LERF calculation to account for plant configuration changes during the extended CT.

6.5. Risk management actions implemented.

6.6. For emergent conditions, the extent of condition assessment for redundant components.

6.7. The total accumulated ICDP and ILERP accrued during the extended CTs.

7. Periodic Documentation:

7.1. The accumulated annual risk above the zero maintenance baseline due to equipment out of service beyond the front-stop CT and comparison to the guidelines for small risk changes in Regulatory Guide 1.174 shall be documented every refueling cycle not to exceed 24 months.

2.3.3 Training

1. Those organizations with functional responsibilities for performing or administering the CRM program shall have required training (e.g., licensed operators, work control personnel, PRA personnel, and station management).

2. Training shall be provided to personnel responsible for performance of RMTS actions. This training should be commensurate with the respective responsibilities of the personnel in the following areas:

    2.1. Programmatic requirements of RMTS program.

    2.2. Fundamentals of PRA including analytical methods employed and the interpretation of quantitative results. This training should include training on the potential impact of common cause failures, model assumptions and limitations, and uncertainties. The training also should address the implications of these factors in the use of PRA results in decision-making applicable to RMTS.

    2.3. Plant specific quantitative and qualitative insights obtained from the PRA.

    2.4. Operation of the plant configuration risk management tool and interpretation of results derived from its application.

2.3.4 PRA Technical Adequacy

Stations electing to implement RMTS shall have a PRA model with the following attributes:

1. The PRA model shall incorporate the attributes contained in Section 4 of this report. The intent of these attributes is to ensure that the PRA provides a reasonable representation of the plant risks associated with the removal of plant SSCs from service.

2. The PRA shall be reviewed to the guidance of Regulatory Guide 1.200 Rev 0 for a PRA which meets Capability Category 2 for the supporting requirements of the ASME internal events at power PRA standard. Deviations from these capability categories relative to the RMTS program shall be justified and documented.

3. The scope of the PRA model shall include Level 1 (CDF) plus large early release frequency (LERF). In addition, RICT and RMAT calculations shall include contributions from external events, internal flooding events, and internal fire events. Inclusion of these factors within the PRA is not explicitly required provided alternate methods (e.g., conservative or bounding analyses) are used to accomplish this requirement.

4. The PRA shall be capable of providing quantitative configuration specific impacts due to planned or unplanned unavailability of equipment within the scope of the CRM program for the operational mode existing at the time an existing CT is extended.

5. If the PRA model is constructed using data points or basic events that change as a result of time of year or time of cycle (examples include moderator temperature coefficient, summer versus winter alignments for HVAC, seasonal alignments for service water), then the RICT calculation shall either 1) use the more conservative assumption at all time, or 2) be adjusted appropriately to reflect the current (e.g., seasonal or time of cycle) configuration for the feature as modeled in the PRA. Otherwise, time-averaged data may be used in establishing the RICT.

6. Common cause treatment as applied in the CRM model is consistent with the PRA model and RMTS guidance.

7. The PRA shall be maintained and updated in accordance with approved station procedures to ensure it accurately reflects the as-built, as-operated plant.

   7.1 The PRA shall be maintained and updated in accordance with approved station procedures on a periodic basis not to exceed two refueling cycles.

   7.2 A process for evaluation and disposition of proposed facility changes shall be established for items impacting the PRA model (e.g., design modifications, procedure changes, etc.). Criteria shall exist in PRA configuration risk management to require PRA model updates concurrent with implementation of facility changes that significantly impact RICT calculations.

   7.3 In the event a PRA error is identified that significantly impacts RICT calculations, corrective actions shall be identified and implemented as soon as practicable in accordance with the station corrective action program.

8. PRA quantification software shall satisfy station software quality assurance requirements.

9. For plants with an at-power PRA that does not directly address lower operating modes, as discussed in Section 2.1, and the plant desires to use the PRA results to calculate RMAs and RICTs for plant configurations that originate in lower plant operating modes, a technically-based argument for application of the Mode 1 and 2 model to other plant operating modes shall be provided (e.g., provide assurance that risk associated with other modes addressed in the RMTS is bounded by the Modes 1 and 2 PRA model).

10. PRA modeling (i.e., epistemic) uncertainties shall be considered in application of the PRA base model results to the RMTS program. This uncertainty assessment is intended to be performed on the PRA base model prior to implementation of the RMTS program and provide insights such that applicable compensatory risk

management actions may be developed to limit the potential impact of these uncertainties. This evaluation should include an LCO specific assessment of key assumptions that address key uncertainties in modeling of the specific out of service SSCs. For LCOs in which it is determined that identified uncertainties could significantly impact the calculated RICT, sensitivity studies should be performed for their potential impact on the RICT calculations. (Reference EPRI-1009652 [6] for one method to determine key uncertainties.) Insights obtained from these sensitivity studies should be used to develop appropriate compensatory risk management actions. Such activities may include highlighting risk significant operator actions, confirming availability and operability of important standby equipment, and assessing the presence of severe or unusual environmental conditions. The intent of these risk management actions is to (in a qualitative manner) minimize the potential adverse impact of the uncertainties. This assessment is only intended to be performed prior to initial implementation of the RMTS program and after a substantial update of the PRA.

2.3.5 Configuration Risk Management Tools

The following specific CRM tool attributes are required for RMTS implementation:

1. Initiating event models include external conditions and effects of out-of-service equipment.
2. Model truncation levels are adequate to maintain associated decision-making integrity.
3. Model translation from the PRA to a separate CRM tool is appropriate; CRM fault trees are traceable to the PRA. Appropriate benchmarking of the CRM tool against the PRA model shall be performed to demonstrate consistency.
4. Any modeled recovery actions credited in the calculation of a RICT shall be applicable to the plant configuration.
5. Configuration of the plant is correctly mapped from systems / components and real time activities to CRM model parameters.
6. Each CRM application tool is verified to adequately reflect the as-built, as-operated plant, including risk contributors which vary by time of year or time in fuel cycle or otherwise demonstrated to be conservative or bounding.
7. Application specific risk important uncertainties contained in the CRM model (that are identified via PRA model to CRM tool benchmarking) are identified and evaluated prior to use of the CRM tool for RMTS applications.
8. CRM application tools and software are accepted and maintained by an appropriate quality program. CRM application tool quality requirements for RMTS include:

8.1 Model configuration control.

8.2 Software quality assurance.

8.3 Training of responsible personnel.

8.4 Development and control of procedures.

8.5 Identification and implementation of corrective actions.

8.6 Program administration requirements.

9. The CRM tool shall be maintained and updated in accordance with approved station procedures to ensure it accurately reflects the as-built, as-operated plant.

9.1 The CRM tool shall be maintained and updated in accordance with approved station procedures on a periodic basis not to exceed two refueling cycles.

9.2 A process for evaluation and disposition of proposed facility changes shall be established for items impacting the CRM tool (e.g., design modifications, procedure changes, etc.). Criteria shall exist to require CRM updates concurrent with implementation of facility changes that significantly impact RICT calculations.

9.3 In the event a PRA or CRM modeling error is identified that significantly impacts RICT calculations, corrective actions shall be identified and implemented as soon as practicable in accordance with the station corrective action program. Entrance into RMTS shall be suspended until these corrective actions have been implemented.

3 IMPLEMENTATION GUIDANCE

This Section provides guidance supporting the RMTS programmatic requirements described in Section 2. This document has been developed to provide the commercial nuclear power industry guidance on risk management issues associated with implementation of Risk-Managed Technical Specifications (RMTS) programs at their facilities. Specifically, this guide is designed to support the implementation of a risk-informed approach to the management of Technical Specification completion times related to SSC safety functions. The report will generally refer to a CT in association with a "plant configuration." The term "plant configuration," a fundamental term applied in this report, is defined in Appendix A and is simply the consolidated state of all plant equipment functionality, (i.e., either functional or non-functional) and associated plant risk-impacting conditions analyzed in the PRA. This term applies to plant equipment functionality or loss thereof for any reason, including applications of both preventive and corrective maintenance. See Appendix A of this guide for a glossary of key terms applicable to RMTS program development and implementation.

Existing conventional Technical Specifications for nuclear power plants specify maximum CT values for specific plant equipment related to the out-of-service time of SSCs that perform plant safety functions. Under the proposed RMTS concept, these CT values are retained in the Technical Specifications as the front-stop CT values. The front-stop CT values may be either those that have historically been established via conventional deterministic engineering methods and judgment or those more recently justified via risk-informed methods in accordance with RG 1.177. Implementation of a RMTS program does not preclude subsequent revision of front-stop CT values in accordance with RG 1.177. Under a RMTS program, operation beyond these front-stop CTs is allowable provided the risk of continued operation can be shown to remain within established risk thresholds.

This report focuses on RMTS implementation to meet the intent of RITSTF Initiative 4B (see Section 1 for background). A RMTS program does not change any of the conventional Technical Specifications LCOs or associated "action statement" requirements. A RMTS program focuses on managing plant risk to prudently allow configuration-based flexible LCO CT values greater than the front-stop CT values and less than or equal to a maximum back-stop CT value. The RMTS process presented in this report integrates regulatory guidance currently in place for other risk-informed applications. In particular, in RMTS applications, the overall plant risk is assessed via processes consistent with the maintenance rule (10CFR50.65), its attendant Regulatory Guide (RG 1.182), and industry implementation guidance (NUMARC 93-01). It is expected that licensees implementing RMTS will use the same PRA models and risk assessment tools for RMTS and 10 CFR 50.65(a)(4).

3.1 RMTS Program Technical Basis

3.1.1 Risk Management Thresholds for RMTS Programs

Risk management thresholds for RMTS program application are established quantitatively by considering the magnitude of the instantaneous core damage frequency (CDF), instantaneous large early release frequency (LERF), incremental core damage frequency (ICDF), and the incremental large early release frequency (ILERF) for the plant configuration of interest. It is important to note that these incremental frequency values are measured from their respective "no-maintenance" or "zero-maintenance" baseline frequencies as determined via the PRA (see definitions of terms in Appendix A).

Guidance for evaluating temporary risk increases by considering configuration-specific risk is provided in NUMARC 93-01, Revision 3 [2]. The risk management thresholds presented in Table 3-1 provide the basis for RMTS program implementation. Table 3-1 presents RMTS quantitative risk management thresholds and RMTS action guidance as well as a comparison of the respective applicable Maintenance Rule thresholds and action guidance from Reference 3.

Table 3-1
RMTS Quantitative Risk Management Thresholds

Criterion*		Maintenance Rule Risk Management Guidance	RMTS Risk Management Guidance
CDF	LERF		
$\geq 10^{-3}$ events/year	$\geq 10^{-4}$ events/year	- Careful consideration before entering the configuration (none for LERF)	- Voluntary entrance into configuration prohibited. If in configuration due to emergent event, implement appropriate risk management actions.
ICDP	ILERP		
$\geq 10^{-5}$	$\geq 10^{-6}$	– Configuration should not normally be entered voluntarily	- Follow the Technical Specification requirements for required action not met.
$\geq 10^{-6}$	$\geq 10^{-7}$	– Assess non-quantifiable factors – Establish compensatory risk management actions	– RMAT and RICT requirements apply – Assess non-quantifiable factors – Implement compensatory risk management actions
$<10^{-6}$	$<10^{-7}$	– Normal work controls	– Normal work controls

* In application of these RMTS criteria, the criteria for both columns apply simultaneously and actions are taken based on the more restrictive one.

In a RMTS program the 10^{-6} and 10^{-7} thresholds for ICDP and ILERP, respectively, are referred to as Risk Management Action (RMA) thresholds and the RMAT is the corresponding risk management action time. The 10^{-5} and 10^{-6} thresholds for ICDP and ILERP, respectively, are referred to as Risk Informed Completion Time (RICT) Thresholds. These thresholds are deemed appropriate for RMTS programs because they relate to integrated plant risk impacts that are occasional and temporary in nature (versus permanent) and are consistent with Reference [4] guidance that has been previously endorsed by the NRC.

3.1.2 RMTS Risk Management Time Intervals

The RMTS process for allowing continued plant operation beyond the conventional Technical Specifications front-stop CT values requires performance of risk assessments based on configuration-specific plant conditions to calculate the Risk Management Action Time (RMAT) and Risk-Informed Completion Time (RICT). The RMAT is the time interval from discovery of a condition requiring entry into a Technical Specification with provisions for utilizing a RICT and which results in a plant configuration other than the zero-maintenance state until the 10^{-6} ICDP or 10^{-7} ILERP RMA threshold is reached, whichever is the shorter duration. The RICT is the time interval from discovery of a condition requiring entry into a Technical Specifications action for a SSC which has the provision to utilize a RICT and which results in a plant configuration other than the zero-maintenance state until the 10^{-5} ICDP or 10^{-6} ILERP threshold is reached, or 30 days, whichever is shorter. The maximum RICT of 30 days is referred to as the back-stop CT. The back-stop CT limit of 30 days is judged to be a prudently conservative administrative limit for configuration risk management. Similar to the 90-day limit for a temporary alteration for maintenance without performing a 10 CFR 50.59 evaluation established in NEI 96-07 "Guidelines for 10 CFR 50.59 Implementation", the 30-day back-stop CT limits the time that is in a condition that is not consistent with the design basis. The 30-day back-stop CT was established based on the fact that some conventional Technical Specification front-stop CT limits are as long as 30 days, and because many nuclear stations would require up to this time period to complete some required complex corrective maintenance and testing for system function recovery. The RMTS approach evaluates the nuclear safety impacts (i.e., changes in risk levels) of specific plant configurations (i.e., equipment unavailability) to produce risk-informed equipment out-of-service times that permit licensees to monitor and manage activities associated with inoperable Technical Specification SSCs while maintaining nuclear safety risk within acceptable limits.

3.2 RMTS Program Implementation

3.2.1 RMTS Process Control and Responsibilities

Implementation of the RMTS risk assessment process should be integrated into station-wide work control processes. The process requires identification of current and anticipated plant configurations and the performance of a quantitative risk assessment applicable to those configurations (i.e., a risk profile). Appropriate actions to manage the risk impacts shall then be determined and implemented if risk thresholds are expected to be exceeded.

The RMTS program structure includes the following attributes:

1. Current (conventional) Technical Specifications structure is retained but applicable systems contain contingencies that allow the use of Risk Managed Technical Specifications.

2. Operability determinations are performed in accordance with existing regulatory guidance and requirements (e.g., NRC Inspection Manual Part 9900 [9]).

3. Defined risk management thresholds (RMA threshold, RICT threshold) are specified.

4. Defined time interval periods (i.e., front-stop CT, RMAT, RICT, and back-stop CT) corresponding to applicable Technical Specification and risk management thresholds are determined.

5. Reference to defined actions in Technical Specifications are specified.

6. Ultimate risk limits are specified to prevent voluntary operation in plant configurations that correspond to high risk conditions (i.e., 10^{-3} CDF or 10^{-4} LERF per year).

The RMTS is intended to supplement the fixed CTs of the current Technical Specifications with provisions that allow the use of specific risk management methods to determine a risk informed completion time based on specific plant configurations in which one or more plant SSC is Technical Specification inoperable. An example structure for implementing the proposed RMTS is illustrated in Table 3-2. Table 3-2 shows an example structure for one system only, but this structure could be repeated for other SSCs.

Table 3-2
Generic Risk-informed CTs with a Back-stop: Example Format.

Actions Condition	Required Action	Completion Time
B. Subsystem inoperable.	B.1 Restore subsystem to OPERABLE status.	72 hours
	<u>OR</u>	
	B.2.1 Determine that the completion time extension beyond 72 hours is acceptable in accordance with established RMTS thresholds.	72 hours
	<u>AND</u>	
	B.2.2 Verify completion time extension beyond 72 hours remains acceptable.	In accordance with the RMTS Program.
	<u>AND</u>	
	B.2.3 Restore subsystem to OPERABLE status.	30 days or acceptable RICT, whichever is less.

Quantitative risk assessments used to support RMTS evaluations shall be performed with a plant specific PRA model approved by station management in accordance with approved station procedures. Fire, seismic and/or flood risks shall also be considered when establishing the duration of a proposed CT extension (See Section 4, PRA Attributes).

In the conduct of RMTS, procedural guidance is required for conducting and using the results of the risk assessment. These procedures should specify the station functional organizations and personnel, including operations, engineering, work management and risk management (PRA) personnel, responsible for each step of the procedures. The procedures should also clearly specify the process for calculating the applicable RICT, implementing RMAs, conducting, reviewing, and approving decisions to exceed the front-stop CT and remove equipment from service.

For stations implementing a RMTS program, the development and maintenance of a "pre-analyzed" list of plant configurations with associated RICT values is permitted. This list does not necessarily need to address all SSCs governed by the Technical Specifications, but should address reasonable or expected combinations of SSCs that would be removed from service.

3.2.2 RMTS Implementation Process

A RMTS program defines the scope of equipment used to define plant configurations. Generally, equipment included within the evaluation of a specific plant configuration is associated with SSCs that are included within the scope of the Technical Specifications and are included in a station's CRM program. Therefore, these SSCs have front-stop CT requirements and can be evaluated via the RMTS-supporting PRA and CRM program. Technical Specifications for Safety Limits, Reactivity Control, Power Distribution, and test exceptions are not in the scope of the RMTS guidelines.

Stations implementing a RMTS program are required to perform a RICT assessment whenever (1) the front-stop CT for an SSC within the scope of the RMTS program is expected to be exceeded or (2) whenever an SSC within the scope of the RMTS program is beyond its front-stop CT and a plant configuration change within the scope of the CRM program occurs (e.g., a SSC within the scope of the plant CRM program is removed from or returned to service).

The PRA provides the analysis mechanism to identify SSCs for which RICT calculations can be applied. The PRA considers dependencies, support systems, and, through definition of top events, cut sets, and recovery actions, it includes those SSCs that could, in combination with other SSCs, result in risk impacts. Thus, an appropriate technical basis exists for RICT calculations. The risk informed assessment scope of SSCs included in a plant CRM program generally includes the following:

1. Those SSCs included in the scope of the plant's Level 1 and LERF (or Level 2 if available), internal (and, if available, external) events PRA, and;

2. Those SSCs not explicitly modeled in the PRA but whose functions can be directly correlated, with appropriate documentation, to those in 1 above (e.g., actuation instrumentation for a PRA modeled function).

Figure 3-1 provides a process flowchart for implementation of the RMTS program.

RMTS PROCESS FLOWCHART

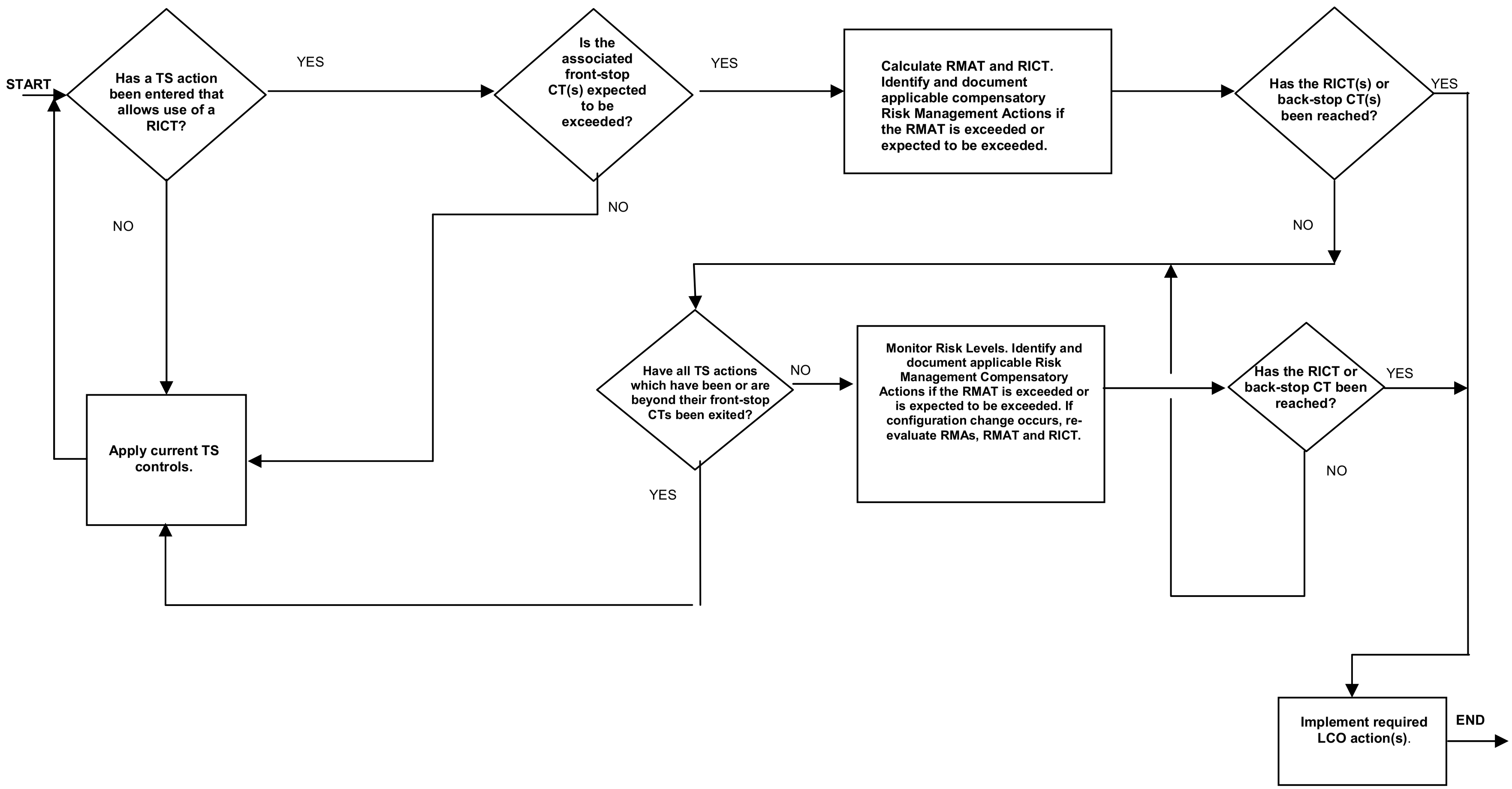

Figure 3-1
Process Flowchart for RMTS RICT Assessment and Implementation

The following provides general guidance for implementation and conduct of a RMTS program.

1. Plant operating conditions (modes) for which RMTS may be applied are defined in Section 2.1.

2. The determination of an applicable RMAT and RICT shall use quantitative analysis approaches. Qualitative risk insights may be used to develop appropriate compensatory risk management actions.

3. The RICT assessment shall assume equipment declared inoperable is also non-functional unless a condition exists that is explicitly modeled in the PRA and the PRA functionality criteria provided in Section 2.3.1 Item 11 are satisfied. In a RMTS program, a RICT exceeding the current front-stop CT may not be applied in cases where a total loss of function has occurred (e.g., all trains of a required Technical Specifications system are determined to be non-functional, such as all trains of Safety Injection or all trains of Component Cooling Water). Unless otherwise permitted by the Technical Specifications, application of RMTS for an entry into a configuration involving a loss of function is not allowed.

4. RICT assessments may be pre-determined (i.e., performed prior to an actual need), or they may be performed on an as-needed basis.

5. Emergent events or conditions (see definition in Appendix A) could change the conditions of a previously performed RICT assessment. Consequently, a revised RMAT and RICT may be required. Emergent conditions may include events such as plant configuration or mode changes, the removal of additional SSCs from service due to failures, or significant changes in external conditions (e.g., selected weather conditions or offsite power availability). The following guidance, consistent with Reference 2, should be applied to such situations:

   - A RICT assessment shall be performed or re-evaluated to address the changed plant configuration on a reasonable schedule commensurate with the safety significance of the condition. This assessment shall be performed within the shorter of 12 hours or the most limiting front-stop CT after a configuration change that affects an RMTS RICT has occurred.

   - Performance (or re-evaluation) of the RICT assessment shall not interfere with, or delay, the operator and/or maintenance crew from taking timely actions to place the plant in a stable configuration, restore the equipment to service, or take appropriate compensatory actions.

   Additionally, the RICT may be recalculated when an affected SSC is restored to an operable condition (i.e., the plant configuration changes).

6. A Technical Specification action statement with the provision to utilize a RICT shall be considered not met whenever the RICT is exceeded. In the event a

Technical Specification LCO is not met, the applicable actions specified by the Technical Specification Action Statement shall be taken.

3.2.3 RMAT and RICT Calculations

In a RMTS program, the conventional Technical Specification definition of equipment "operability" (see Appendix A) applies, just as it does under existing Technical Specifications. Thus, equipment "operability" is applied by station operating staffs to evaluate whether SSC LCOs are met and whether to enter or exit Technical Specifications actions. The information contained in NRC Inspection Manual 9900 [9] should be used as guidance in making operability determinations.

If a degraded or nonconforming condition existing on a component can be explicitly modeled by the station's PRA, then a situation specific RICT can be calculated. In these cases the PRA analysis supporting the RICT calculation must be documented, retrievable, and able to be referenced using normal operator documentation mechanisms (e.g., Control Room Logs or other equivalent methods). In the RICT calculation, equipment PRA functionality may be considered. The evaluation for the applicability of crediting "PRA functionality" shall be conducted in accordance with the guidance provided in Item 11 of Section 2.3.1. This guidance is intended to address separate operability and PRA functionality assessments which would allow a component to be considered both inoperable and PRA functional based on an evaluation of the same degraded condition. Specific examples are provided for each of the conditions identified in Items 11.1 through 11.3 of Section 2.3.1.

Item 11.1 Examples (If a component is declared inoperable due to degraded performance parameters, but the affected parameter does not and will not impact the success criteria of the PRA model, then the component may be considered PRA functional for purposes of the RICT calculation.)

Example 1: A valve fails its in-service testing stroke time acceptance criteria, but the response time of the valve is not relevant to the ability of the valve to provide its mitigation function (i.e., the valve is normally open and required to be open in the PRA). The valve may be considered PRA functional in the RICT calculations.

Example 2: A pump is declared inoperable due to increasing bearing temperatures. Although the temperature of the bearing is not immediately impacting on the pump success criteria (i.e., pump flow), the basis for declaring it inoperable is the anticipated degradation and loss of function. Since the condition has been judged to warrant declaring the pump inoperable, it should not be simultaneously considered PRA functional for the RICT calculations.

Item 11.2 Examples (If the functional impact of the condition causing the inoperability is capable of being assessed by the PRA model, then the remaining unaffected functions of the component may be considered PRA functional in the RICT calculation.)

Example 1: A valve is inoperable but secured in the closed position, and can be addressed in the PRA model by failing functions which require an open valve, but crediting functions which require a closed valve.

Example 2: A component is inoperable due to a non-functional seismic support, and can be addressed in the PRA model by failing the component for seismic initiators but crediting the component function for other initiators.

Example 3: A component is inoperable due to unavailability of a normal power supply when a backup is PRA functional, and can be addressed in the PRA model by failing the normal power supply when the backup power supply is appropriately included in the model.

Example 4: A component is inoperable due to invalid qualification for a harsh environment, but the PRA provides the capability to discern the scenarios which result in harsh environments.

Item 11.3 Examples (If the condition causing a component to be inoperable is not modeled in the PRA, and the condition has been evaluated and documented in the RMTS program as having no risk impact, then the RICT may be calculated assuming availability of the inoperable component and its associated system, subsystem or train. If there is no documented basis for exclusion, or if the condition was screened as low probability, then the inoperable component must be considered not functional.)

Example 1: A pump backup start feature is inoperable and the feature is not credited in the PRA model (assumed failed); the RICT calculation may assume availability of the associated pump since the risk of the non-functional backup start feature is part of the baseline risk.

Example 2: An interlock is inoperable and is not modeled in the PRA because it was identified as highly reliable. In this case the RICT calculation must assume the affected system, subsystem, or train is not functional.

RICT assessments do not allow credit to be taken for probability of repair of the affected Technical Specifications equipment in a configuration-specific RICT calculation.

For planned maintenance in which a condition requiring a RICT assessment is applicable, a plant configuration-specific RICT assessment should be performed to determine RMAT and RICT values prior to commencing the maintenance.

- If the anticipated duration of the maintenance does not extend beyond the RMAT, normal work controls may be used to perform the maintenance in accordance with Maintenance Rule (a)(4) requirements.

- If the anticipated duration of the maintenance extends beyond the RMAT or an emergent condition has caused the RMAT to be exceeded, appropriate compensatory risk management actions shall be defined and implemented as necessary to control plant risk.

- If the anticipated duration of maintenance extends beyond the RICT, the configuration should not be entered.

Note that for preplanned maintenance activities for which the RMAT is anticipated to be exceeded, RMAs shall be implemented at the earliest appropriate time.

In instances in which an emergent event occurs, calculation of an applicable RICT is always secondary to performance of actions necessary to place the plant in a stable configuration. Additionally, during events in which Technical Specifications LCOs are not met but for which the plant remains in a state in which conditions continue to change, the Technical Specifications CTs shall be governed by the current Technical Specifications front-stop CTs until a stable configuration is reached. An explicit example of this situation is provided for clarity. Consider the case where the plant DC electrical distribution system is in a condition where the batteries are discharging and DC bus voltage is decreasing. In this condition, the plant should not consider extension of the Technical Specifications CT until such time as the plant is placed in a stable condition.

If during application of a specified RICT, the plant transitions to a different plant configuration that impacts SSCs within the scope of the CRM program (e.g., due to emergent conditions), then a revised RICT is required to be calculated. Stations implementing RMTS shall have configuration risk management tools (i.e., safety monitors, risk monitors, pre-solved configuration risk databases, etc.) that can be applied to calculate configuration risk by the on-shift station staff within relatively short periods of time following identification of the configuration. In the event emergent conditions occur while a RICT is in effect, the plant would (1) take actions appropriate to managing risk in the current condition, and then (2) assess the risk significance of the condition. The plant would then calculate a revised RMAT and RICT. This calculation must be accomplished within the front-stop CT of the most limiting action applicable to the new plant configuration; however, this calculation shall be completed within a maximum time period of 12 hours from the time the configuration change occurred.

In a RMTS program the revised RMAT and RICT are effective from the time of entry into the condition of the initial RMTS for which a RICT is applied. The associated RICT “time-clock” is not reset to zero at the time the modified or new configuration occurs. Thus, it is possible in a RMTS framework, that a RICT can be revised several times as SSCs are removed from and returned to service. Only when the plant satisfactorily exits all applicable Technical Specifications actions where the associated front-stop CT has been exceeded can the RICT "time-clock" be re-set to zero. The RICT re-evaluation process is required whenever emergent conditions change the configuration risk profile of the plant. This includes non-Technical Specifications equipment functions that are in the scope of the CRM program and which are involved in the emergent conditions. By incorporating a configuration risk management approach to Technical Specifications, a RMTS program can result in lower cumulative risk over time for the RMTS-implementing station as compared to a conventional Technical Specifications safety management process for the same station.

In cases where an emergent condition arises that may place the plant in a condition where it has exceeded the revised RMAT, the station staff would implement appropriate compensatory measures or compensatory risk management actions, including, as appropriate, transitioning the plant to a lower-risk configuration (i.e., restoring equipment to service or transition to a lower plant operating mode). In any case where a plant reaches or is found to have exceeded the specified configuration specific RICT thresholds of Table 2-2 are exceeded, the plant shall consider the required action to not be met and follow the Technical Specification requirements, including any associated requirement for plant shutdown implementation.

3.2.4 Examples Demonstrating Application of RMAT and RICT in RMTS Programs

There are two important configuration risk concepts used in the implementation of a RMTS program to manage risk: instantaneous risk and cumulative risk. Figures 3-2 and 3-3 illustrate these concepts. Figure 3-2 presents an example of an instantaneous core damage frequency (CDF) profile for a calendar week. Figure 3-3 presents an incremental core damage probability (ICDP) profile for the same example week.

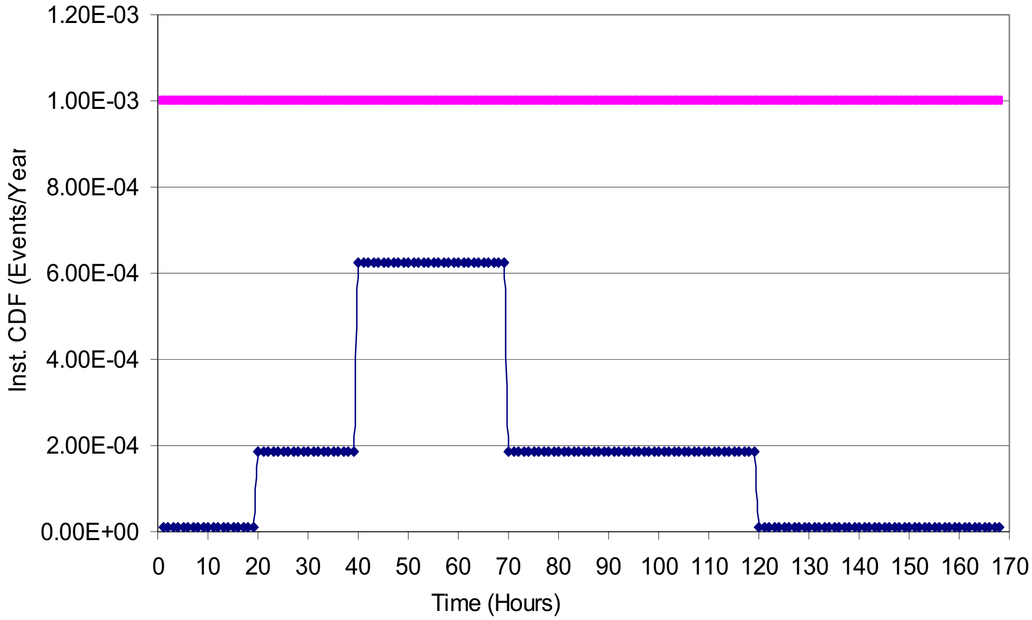

Figure 3-2
Configuration Risk Management – Instantaneous CDF Profile Example

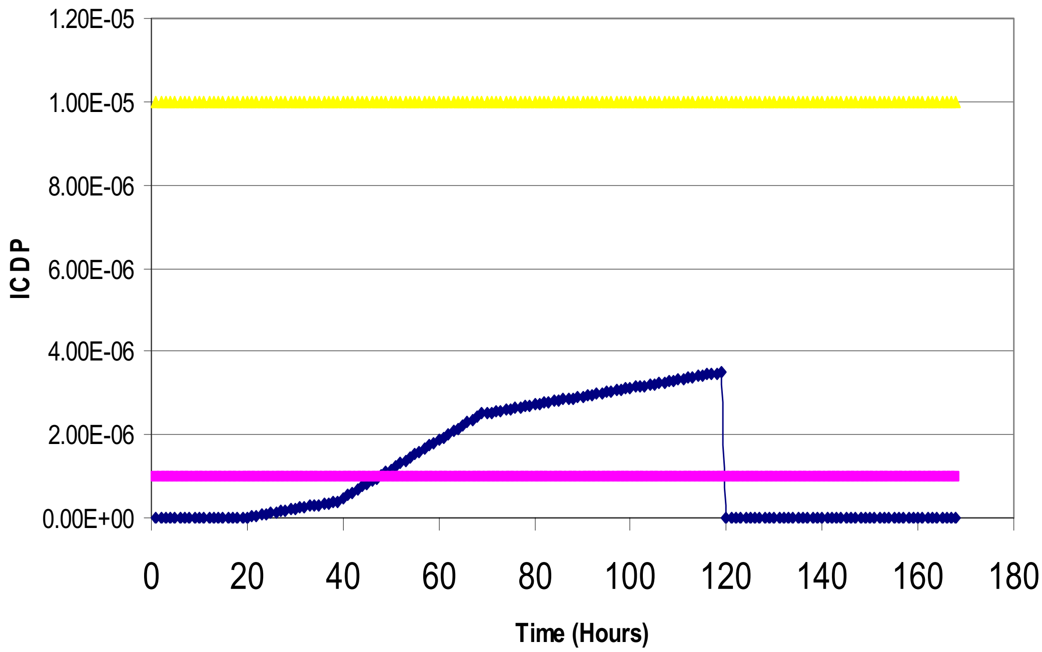

Figure 3-3
Configuration Risk Management – Instantaneous CDP Example

Figure 3-2 shows an example where the first step increase in instantaneous CDF, from the zero-maintenance state, at time = 20 hours is for a planned maintenance activity, and the second step increase in instantaneous CDF at time = 40 hours is due to an emergent unplanned failure discovered in another system. In this example, the emergent failure function is recovered at time = 70 hours, and the originally planned maintenance continues until time = 120 hours. It is important to note that before time = 20 hours and after time = 120 hours, the instantaneous CDF is not zero (as it may appear in this figure due to size resolution), but is equal to the zero-maintenance CDF for the plant (10^{-5} in this example). The horizontal straight-line upper limit shown in Figure 3-2 is the Instantaneous CDF risk threshold for RMTS (= 10^{-3} events per year). A similar instantaneous LERF risk threshold for RMTS is established at 10^{-4} events per year. It is also important to note that this is an example provided for conceptual purposes only. In general, plant-specific zero-maintenance CDFs and plant configurations will be lower, which will result in less risk accumulation over greater periods of time.

Figure 3-3 shows the same example plant configuration versus time profile for incremental core damage probability (ICDP). ICDP does equal zero whenever the zero-maintenance configuration is in effect, but begins to rise at time = 20 hours when the plant is placed in the originally planned plant configuration. When the plant transitions to the second plant configuration at time = 40 hours (when the emergent condition occurs or is discovered), the slope of the ICDP profile increases until the function of the emergent failure is recovered at time = 70 hours. At this time, the slope of the ICDP curve returns to its original value for the original system being out of service (i.e., the value at time = 20 hours). This profile continues until the plant is returned to the zero-maintenance configuration at time = 120 hours. Within the context of RMTS, plant risk is evaluated with respect to particular plant configurations (either planned or emergent). Thus, at the completion of the evolution for which RMTS is applicable, the ICDP profile is defined to return to zero (as shown in Figure 3-3 at time = 120 hours). Figure 3-3 shows two horizontal lines, the lower for the RMA threshold value (ICDP = 10^{-6}), and the higher for the RICT threshold value (ICDP = 10^{-5}). In this example, the station staff would be required to implement Risk Management Actions (RMAs) once the configuration risk ICDP profile increases above 10^{-6} (at approximately time = 47 hours in this example). In accordance with Section 2.1.3 Item 3, for maintenance activities for which the RMAT is anticipated to be exceeded, RMAs shall be implemented at the earliest appropriate time. The concepts shown in Figures 3-2 and 3-3 are also applied to large early release probability (LERP) thresholds in RMTS.

Figure 3-4 provides a simple example of the RMTS process for inoperability of a SSC followed by an emergent event which modifies the risk profile causing changes in the plant configuration RMAT and RICT values. This example is intended to explicitly demonstrate the application of these values in a RMTS program. At time

= 0, the RMTS SSC becomes inoperable for a duration anticipated to exceed the front-stop CT. In this configuration, a RMAT and RICT are calculated. As evident in the figure, the RMAT would be exceeded at time = 7 days. If the anticipated duration of the activity exceeds this time, appropriate compensatory risk management actions will be developed and implemented prior to reaching the RMAT. Again, in accordance with Section 2.1.3 Item 3, the RMAs shall be implemented at the earliest appropriate time. ince the 10^{-5} ICDP threshold is not reached within the 30 day back-stop CT, the applicable RICT is set at 30 days.

At time = 5 days an emergent event occurs which removes a second SSC from service. At this time, the RMTS program requires recalculation of the RMAT and RICT to apply to the new plant configuration. In this plant configuration the RMAT now occurs very soon after the emergent event occurs, thus necessitating development and rapid implementation of additional compensatory RMAs, Additionally, since the 10^{-5} ICDP threshold is reached at time = 27 days, the RICT is revised to reflect this. The start of the time for this configuration to be exited is taken from the time at which the original SSC was declared inoperable and NOT the time at which the emergent event occurred.

In this condition, the RMTS provision applies separately to each ACTION for which it is entered (i.e., RMTS is applied as an extension of the ACTION statement of the referencing Technical Specification). Although a particular ACTION with the CT extended may be exited when the affected SSC is restored to operable status, the accumulated risk of that configuration will continue to contribute to the configuration risk for the associated entry into RMTS until all affected ACTIONs are exited or within their front-stop CT. Application of the RMTS separately to each ACTION also means that the 30-day back-stop CT limit applies separately to each action.

In the example shown in Figure 3-4, at time = 20 days, the second SSC (i.e., the one which became inoperable due to the emergent event at time = 5 days) is restored to service (i.e., returns to a Technical Specification operable condition). At this time, the RICT may be recalculated to reflect the new plant configuration accounting for the cumulative risk accrued during the evolution from time = 0. In this configuration, the 10^{-5} ICDP is not reached until the after the 30 day back-stop CT. The RICT for System 1 may now be reset to 30 days from the time the first system became inoperable. Also, notice that since the cumulative risk at this point is greater than the 10^{-6} ICDP threshold; implementation of appropriate compensatory risk management actions continue to be required.

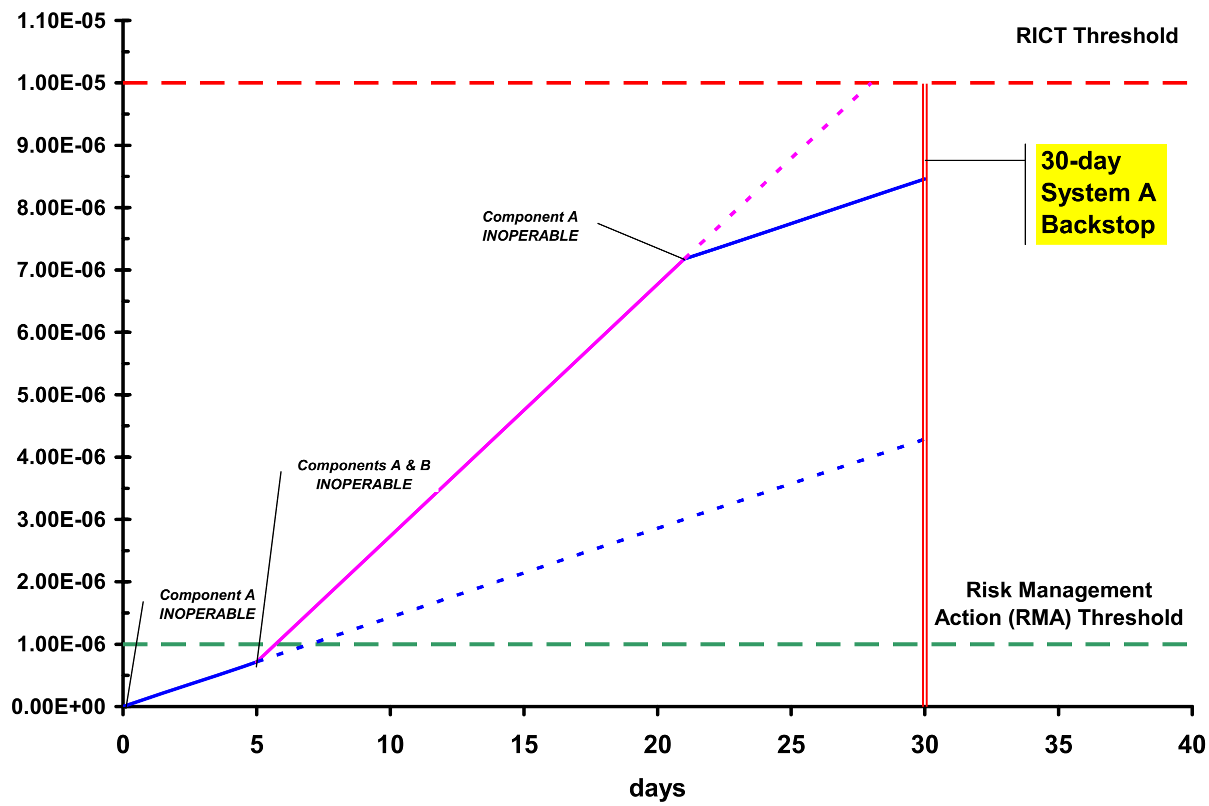

Figure 3-3
Configuration Risk Management – Illustration of Risk Accrual for RICT Calculation

For preventive maintenance conditions which are planned in advance and there is an expectation that the front-stop CT will be exceeded, the RMAT and RICT values should be computed prior to placing the system in an inoperable condition. Furthermore, in the planning of removal of SSCs from service the station should routinely plan to target incremental CDF/LERF values below the Maintenance Rule “normal maintenance level” of 10^{-6} and 10^{-7} respectively. Should preventive maintenance activities be anticipated to exceed the RMAT thresholds, appropriate RMAs should be identified and, as appropriate, implemented before the condition is entered.

3.3 RMTS Assessment Methods

Sections 3.3.1 and 3.3.2 provide guidance regarding quantitative and qualitative considerations, respectively.

3.3.1 Quantitative Considerations

The assessment process shall be performed via tools and methods that incorporate quantitative information from the PRA. Acceptable processes for quantitative assessment include direct assessment of configurations via the PRA model, use of on-line safety/risk monitors, or via a comprehensive set of pre-analyzed plant configurations. To properly support the assessment, the PRA must have the attributes specified in Section 2.3.4 unless otherwise justified (also see Section 4.1, PRA Attributes), and it must reflect the actual plant configuration consistent with the RMTS program scope. Additionally, the CRM program / tool must have the attributes specified in Section 2.3.5 unless otherwise justified (also see Section 4.2, CRM Attributes), and must reflect the actual plant configuration consistent with the RMTS program scope.

3.3.2 Qualitative Methods

RMTS programs are fundamentally based on the ability to calculate a RICT, and therefore, are inherently based on quantitative risk analysis. These quantitative analyses can include bounding analyses. Guidance on bounding analyses for PRA applications is provided, for example, in the industry guidance [5] for implementation of 10 CFR 50.69.

Although the calculation of a RICT is quantitative, qualitative assessments are an important part of the RMTS process used, where appropriate, to supplement the quantification and develop appropriate compensatory risk management actions. Qualitative assessments may be applied to confirm that the aspects not comprehensively addressed in the quantitative assessment have negligible effect on the calculated RICT.

3.3.3 Cumulative Risk Tracking

One overall objective of RMTS is to provide plant configuration control consistent with Regulatory Guide 1.174 over long periods of implementation. The purpose of this tracking is to demonstrate the risk accumulated as a result of SSC inoperability beyond the front-stop CT is appropriately managed. To accomplish this goal, the impact of RMTS implementation on the baseline risk metrics should be periodically assessed and managed as appropriate to ensure there is no undue increase. Long-term risk should be managed via an administrative process incorporated within the station RMTS program, and, unlike the RICT implementation described in Table 3-2, would not be directly linked to Technical Specifications required actions. One example of such tracking would be to record all RMTS entries where inoperable SSCs extend beyond their respective front-stop CT and track the associated accumulated risk during those plant configurations. An alternative, more continuous, example of an acceptable general administrative cumulative risk management process would be tracking risk via a 52-week rolling average CDF trend that is updated weekly to account for the actual cumulative risk incurred above the zero-maintenance baseline risk. Alternatively, the plant could meet this requirement by documenting the zero-maintenance baseline risk for the plant along with the changes or "deltas" from that baseline, or through quantifying the "deltas" from the baseline on a periodic basis. This administrative process for cumulative risk management should include a requirement to document specific corrective actions and, if necessary, for ensuring operation remains within Regions II or III of Figures 3 and 4 of NRC Regulatory Guide 1.174 [4]. The RMTS program implementing procedure should clearly describe how cumulative risk tracking and associated "triggers" for self-assessment and corrective action will be implemented within the station-specific RMTS program.

Regardless of the method used, the station must track the risk associated with all entries beyond the front-stop CT. This information should be evaluated periodically against the guidance of Regulatory Guide 1.174.

3.3.4 Uncertainty Consideration in a RMTS Program

PRAs applied for RMTS implementation should appropriately consider the issue of uncertainty (see Reference [6] for guidance on treatment of uncertainty in PRAs). This will identify which key base PRA modeling assumptions are important to ensure the RMTS decision-making process is robust. RMTS-implementing stations must have PRAs of acceptable quality and capability yielding zero-maintenance CDF and LERF results that meet established criteria applicable to 10CFR50.65(a)(4) applications. Application of PRA calculated values for configuration risk compared with the PRA quality acceptance guidelines provided herein provides adequate confidence that RICT calculations are safe and appropriate for use in the RMTS decision-making process.

The RMAT and RICT calculations are by definition changes to CDF (i.e., delta-CDF) in that they represent changes from baseline risk values based on equipment out-of-service. In this regard, parameter or aleatory uncertainties are unbiased and tend to cancel since only a change in CDF from equipment out-of-service is being determined.

In an RMTS program the issue of epistemic uncertainty (or modeling uncertainties) associated with the PRA is addressed by evaluation of PRA base model uncertainties prior to the initial implementation of the RMTS program. The station will perform an assessment of the impact of PRA modeling assumptions on RICT calculations for LCOs within the program scope. This evaluation includes an LCO specific assessment investigating the impact of key PRA assumptions on configuration risk. In support of LCO specific risk assessments, the licensee should:

1. Identify the key sources of uncertainty in the PRA consistent with the expectations of RG 1.200. An example process for identifying key assumptions is found in EPRI-1009652 [6].

2. For each LCO within the scope of the RMTS program, identify those SSCs or PRA elements (e.g., operator actions, initiating events, etc.) that appear in the same functional core damage sequences as the component for which the LCO is to be determined.

3. Identify key model uncertainties that may impact the SSCs or PRA elements identified in step 2.

4. Perform sensitivity studies on those uncertainties which could potentially impact the result of a RICT calculation. For those sequences in which uncertainty is found to have a potential significant impact on the calculated RICT, identify appropriate compensatory risk management actions and incorporate these into the station RMTS program implementation guidance.

Although this assessment is not intended to be exhaustive, the general guidance should be that the impact of the key modeling uncertainties and associated key assumptions is limited when reasonable alternate modeling assumptions do not result in significant increases to plant risk. Where the uncertainty impact is identified to result in a significant risk increase, risk management actions are identified to minimize this impact. In instances where assumptions are judged to be overly optimistic (i.e., non-conservative) for this application, use of alternate assumptions should be considered. This assessment is only intended to be performed prior to initial implementation of the RMTS program and after a substantial update of the PRA.

3.3.5 External Events Consideration

When evaluating risks for use in a RMTS program, plant PRA models should include internal floods, fires, and other external events that the PRA would indicate as risk significant and that would impact maintenance decisions. For stations without external events PRAs incorporated into their quantitative CRM Tools, or in cases where the existing external event PRA does not adequately address the situation, the station should apply the following criteria to support maintenance activities beyond the front-stop CT:

1. Provide a reasonable technical argument (to be documented prior to the implementation of the associated RICT) that the configuration risk of interest is dominated by internal events, and that external events, including internal fires, are not a significant contributor to configuration risk (i.e., they are not significant relative to a RICT calculation).

OR

2. Perform a reasonable bounding analysis of the external events, including internal fires, contribution to configuration risk (to be documented prior to the implementation of the associated RICT) and apply this upper bound external events risk contribution along with the internal events risk contribution in calculating the configuration risk and the associated RICT.

   OR

3. For limited scope RMTS applications, a licensee may use pre-analyzed external events and internal fire analyses to restrict RMA thresholds and identify and implement compensatory risk management actions. For the duration of the configuration of interest, these actions should be supported by analyses and provide a reasonable technical argument (to be documented prior to the implementation of the associated RICT) that external events, including internal fires, are adequately controlled so as to be an insignificant contributor to the incremental configuration risk. Any RMAs credited in this manner shall be proceduralized and appropriate training provided.

The “reasonable bounding analyses” identified in Item 2 above must be case-specific and technically verifiable, and they must be shown to be conservative from the perspective of RICT determination (i.e., result in conservative RICT values). An example of a bounding analysis method for screening fire risk in a RMTS program that may be used is presented in Reference [7]. It is the intent of the RMTS process to consider the total plant risk. Stations with full scope PRAs will be able to perform integrated quantitative risk assessments to support their RMTS programs. However, it is expected that many of the stations intending to utilize an RMTS program will have robust Level 1 and LERF PRAs; however, they may need to incorporate additional methods and processes to evaluate the risk impact associated with fire, seismic, and external flooding. When external events PRA is used in the quantitative CRM Tool to address external events applicable to RMTS, the PRA and CRM capability requirements must be commensurate with the guidelines specified in Sections 2.3.4, 2.3.5, 4.1 and 4.2 of this report.

In addition to the evaluation of external events for potential RICT impact, these events should be evaluated for insights which permit development and implementation of applicable risk management actions. The results of these evaluations may be incorporated into plant programmatic controls (e.g., procedures, checklists, etc.).

3.3.6 Common Cause Failure Consideration

Common cause failures are required to be considered for all RICT assessments. For all RICT assessments of planned configurations, the treatment of common cause failures in the quantitative CRM Tools may be performed by considering only the removal of the planned equipment and not adjusting common cause failure terms.

For RICT assessments involving unplanned or emergent conditions, the potential for common cause failure is considered during the operability determination process. This assessment is more accurately described as an "extent of condition" assessment. Licensed operators recognize that an emergent condition identified on a Technical Specifications component may have the potential to affect a redundant component or similar components. In addition to a determination of operability on the affected component, the operator should make a judgment with regard to whether the operability of similar or redundant components might be affected. In accordance with the operability determination guidance in Part 9900 of the NRC Inspection Manual (provided in Regulatory Information Summary 2005-20), the determination of operability should be done promptly, commensurate with the safety significance of the affected component. If a common condition affects the operability of multiple components (e.g., that more than one common cause group functional train is affected), action should be taken via the Technical Specifications.

Based on the information available, the licensed operator is often able to make an immediate determination that there is reasonable assurance that redundant or similar components are not affected. Using judgment with regard to the specific condition, the operator may direct that similar or redundant components be inspected for evidence of the degradation. For conditions where the operator has less information, assistance from other organizations, such as Station Engineering, is typically requested. These support organizations continue to perform the evaluation promptly, as described above. The guidance contained in Part 9900 of the Inspection Manual is used as well as conservative decision-making for extent of condition evaluations. The components are considered functional in the PRA unless the operability evaluation determines otherwise.

While quantitative changes to the PRA are not required, the PRA should be used as appropriate to provide insights for the qualitative treatment of potential common-cause failures and RMAs that may be applied for the affected configuration. Such information may be used in prioritizing the repair, ensuring proper resource application, and taking other compensatory measures as deemed prudent by station management.

3.4 Managing Risk

Risk Management uses both quantitative and qualitative risk assessment methods in plant decision-making to identify, monitor, and manage risk levels. This process involves coordination with planning, scheduling, monitoring, maintenance, and operations activities.

The objective of configuration risk management is to manage the planned and emergent risk increases from maintenance activities and equipment failures and to maintain them within acceptable limits. In the context of an RMTS program, this control is accomplished by using RMAT values to identify higher risk evolutions to plan and schedule maintenance such that the risk increases are identified and appropriately managed. For activities in which the RMAT is anticipated to be exceeded, the station staff should take additional actions beyond routine work controls and endeavor to maintain adequate margin between the actual risk level and the RMA threshold. For activities in which the anticipated maintenance duration will exceed the RMAT, organizational controls beyond what are considered normal (i.e. risk management actions) shall be initiated with station priorities directed to returning risk levels to below the ICDP / ILERP threshold. For preplanned maintenance activities for which the RMAT is anticipated to be exceeded, RMAs shall be implemented at the earliest appropriate time including, where appropriate, for the entire duration of the maintenance activity.

A key risk management activity is assessing the risk impact of planned maintenance. In conjunction with scheduling the sequence of activities, compensatory risk management actions may be taken that reduce the temporary risk increase, if determined to be necessary. Since many of the compensatory risk management actions involve non-quantifiable factors, the risk reduction would not necessarily be quantified. The following sections discuss approaches for the establishment of thresholds for the use of compensatory risk management actions.

3.4.1 Risk Management Action Incorporation in a RMTS Program

Using this framework for risk management, the station staff can calculate RMATs and RICTs. For planned maintenance, target outage times should be established at low risk levels (See Table 3-1) and should be accompanied by normal work controls. The process to manage risk levels assesses the rate of accumulation of risk in specific plant configurations and determines the acceptability of continued plant operation (beyond the front-stop CT) based on the risk assessment, alternative actions, and the impact of compensatory risk management actions. If the target outage time exceeds the RMAT, RMAs must be considered and, where deemed appropriate by station management and operators, implemented. RMAs are specific activities implemented by the plant to monitor and control risk. Section 3.4.3 provides some examples of RMAs. If the target outage time reaches the RICT, action must be taken to implement the applicable Technical Specification action statement(s).

RMAs may be quantified to determine revised RICT values, but this quantification of RMAs is neither expected nor required, as omission of this RMA quantification results in conservative RICT values. For evolutions where compensatory RMAs are planned in support of maintenance (e.g., temporary diesels), it may be beneficial to quantify RMAs, to determine realistic RICT values. For a station to be eligible to quantify RMAs and credit them in the RICT determination, it must be able to determine the associated RMA risk impacts on and from the following: SSC functionality, new configurations of existing PRA basic event cut sets, new temporary equipment functions, and new or modified human actions. Actions that will be credited shall be proceduralized with responsible implementing staff trained on application of the procedures. If the station chooses to quantify RMAs, it must apply a documented and approved process that meets the PRA and CRM program requirements described in this guidance document.

During the time period following the RMAT but before the expiration of the applicable RICT, plants will normally progressively implement risk management compensatory actions commensurate with the projected risk during the plant configuration period. These compensatory actions are identified and implemented by station personnel and approved by station management based on plant conditions. Such compensatory measures may include but are not limited to the following:

- Reduce the duration of risk sensitive activities.
- Remove risk sensitive activities from the planned work scope.
- Reschedule work activities to avoid high risk-sensitive equipment outages or maintenance states that result in high risk plant configurations.
- Accelerate the restoration of out-of-service equipment.
- Determine and establish the safest plant configuration.

Contingency plans can also be used to reduce the effects of the degradation of the affected components by utilizing the following:

- Specific operator actions.
- Increased awareness of plant configuration concerns and the effects of certain activities and transients on plant stability.
- Administrative controls.
- Ensure availability of functionally redundant equipment.

3.4.2 Qualitative Considerations Supporting Action Thresholds

RMTS risk management action thresholds (i.e., plant conditions and associated configuration risk levels determining when compensatory risk management actions are required) must be established quantitatively, but they can be supported qualitatively, if necessary. Qualitative assessment can be used to support identification and implementation of risk management compensatory actions for specific plant and site conditions present at the time SSCs are out of service, by considering factors outside the scope of the PRA (e.g., weather conditions, grid conditions, etc.), the performance of key safety functions, or remaining mitigation capability.

3.4.3 Examples of Risk Management Actions

Determining actions, individually or in combinations, to control risk for maintenance activities is specific to the particular activity, plant configuration, its impact on risk, and the practical means available to control the risk. Normal work controls would be employed for configurations having predicted risk levels below the RMA thresholds. For these configurations, no additional actions to address risk management are necessary.

Risk management actions, up to and including plant shutdown, should be implemented (and may be required by the RMTS program) for plant configurations whose instantaneous and cumulative risk measures are predicted to approach or exceed the RMTS thresholds. The benefits of these actions may or may not be easy to quantify. These actions are aimed at providing increased risk awareness of appropriate station personnel, providing more rigorous planning and control of the particular maintenance activity, and taking steps to control the duration and magnitude of the increased risk. Examples of risk mitigation / management actions are as follows:

1. Actions to provide increased risk awareness and control:
   - Discuss the planned maintenance activity and the associated plant configuration risk impact with operations and maintenance shift crews and obtain operator awareness and approval of planned evolutions.
   - Conduct pre-job briefing of maintenance personnel, emphasizing risk aspects of planned plant evolutions.
   - Request/require that system engineer(s) be present for the maintenance activity, or for applicable portions of the activity.
   - Obtain station management approval of the proposed activity.
   - Identify return-to-service priorities.
   - Identify important remain-in-service priorities.
   - Place warning signs or placards in the entry ways to protect other in-service risk significant equipment.
2. Actions to reduce duration of maintenance activity:
   - Pre-stage required parts and materials to be prepared for likely contingencies.

- Walk-down the anticipated associated system tagout(s) and key equipment associated with the specified maintenance activity(ies) prior to conducting actual system tagout(s) and performing the maintenance.
- Develop critical activity procedures for risk-significant configurations, including identification of the associated risk and contingency plans for approaching/exceeding the RICT.
- Conduct training on mockups to familiarize maintenance personnel with the activity prior to performing the maintenance.
- Perform maintenance around the clock rather than “day-shift only”.
- Establish contingency plans to restore key out-of-service equipment rapidly if and when needed.

3. Actions to minimize the magnitude of risk increase:
    - Minimize other work in areas that could affect related initiating events (e.g., reactor protection system (RPS) equipment areas, switchyard, diesel generator (D/G) rooms, switchgear rooms) to decrease the frequency of initiating events that are mitigated by the safety function served by the out-of-service SSC.
    - Identify remain-in-service priorities and minimize work in areas that could affect other redundant systems (e.g., HPCI/RCIC rooms, auxiliary feedwater pump rooms), such that there is enhanced likelihood of the availability of the safety functions at issue served by the SSCs in those areas.
    - Establish alternate success paths (provided by either safety or non-safety related equipment) for performing the safety function of the out-of-service SSC.
    - Establish other compensatory measures as appropriate.
    - Monitor RMTS program to ensure application is consistent with station risk-management expectations.
    - Expedite equipment return to service to reduce risk levels.
    - Postpone plant activities, if appropriate, to maintain or reduce risk levels.

3.5 Documentation

Stations implementing a RMTS program shall provide documentation of the programmatic requirements associated with the RMTS and of the individual RICT evaluations. This documentation shall be of sufficient detail to permit independent evaluation of the assumptions, analyses, calculations, and results associated with the RICT assessments. The specific documentation requirements are provided in Section 2.3.2.

3.6 Training

Stations implementing a RMTS program shall provide training in the programmatic requirements associated with the RMTS program and of the individual RICT evaluations to personnel responsible for determining Technical Specifications operability decisions or conducting RICT assessments. The specific training requirements are provided in Section 2.3.3.

4
PRA AND CONFIGURATION RISK MANAGEMENT TOOL ATTRIBUTES

The application of the RMTS program to specific plant configurations requires the determination of a RMAT and RICT. This determination requires a quantitative risk estimate. The basis for these risk estimates is the application of a quantitative configuration risk management (CRM) tool, which is a derivative of the PRA. The scope and quality of the plant PRA and associated CRM tools must be commensurate with the risk impact and scope of the application. Furthermore, the PRA aspects of the CRM tool shall comply with NRC Regulatory Guide 1.200 guidance to the extent appropriate for the specific application. Two documents, Regulatory Guide 1.200 and this guideline, address the requirements for PRA scope and capability for application to the RMTS program. CRM tools applied for RICT calculations also must meet the same quality assurance requirements as their respective underlying PRAs approved for risk-informed applications via Regulatory Guide 1.200. For some operating modes and some initiating events (initiators) detailed below, bounding CRM methods may be used in addition to or instead of the CRM tool. This section describes the attributes of the PRA, the CRM tool, and bounding CRM methods that are necessary to support the RMTS program.

4.1 PRA Attributes

In general, the quantitative risk assessment (plant PRA for RMTS) should be based on the station Configuration Risk Management Program supported by the PRA calculations. At a minimum, the PRA applied in support of a RMTS program shall include a Level 1 PRA with LERF capability. The scope of this PRA shall include credible internal events, including internal flood and internal fires. Other external events should be considered in the development of the RMTS program to the extent these events impact RMTS decisions. It is preferred that these impacts be modeled such that they are explicitly included in the calculation of a RICT. However, where prior evaluation or alternative methods (e.g., bounding analyses) can demonstrate that one or more of the challenges are not significant to the site or the application, quantitative modeling may be omitted.

For application to RMTS the scope of the PRA directly addresses plant configurations during Modes 1 and 2 of reactor operation. Where the PRA is to be used to extend CTs that originate in the lower modes described in Section 2.1, the PRA model must directly address lower operating mode configurations, or a technically-based argument for application of the Mode 1 and 2 model to these other operating modes must be provided (e.g., it must provide assurance that risk associated with other modes addressed in the RMTS is bounded by the Modes 1 and 2 PRA event sequences).

The PRA must have an update process clearly defined by station procedures or instructions.

The PRA model attributes and technical adequacy requirements for RMTS applications must be consistent and compatible with established ASME standards requirements, as modified by NRC Regulatory Guide 1.200 Rev 0. Plant A and B level Findings and Observations arising from the PRA peer review should be resolved or otherwise dispositioned. It is expected that, in general, the PRA which supports RMTS shall meet Capability Category 2 requirements and any exceptions to meeting those requirements shall be justified. For limited scope applications, the PRA capability shall be appropriate to the Technical Specifications system(s) of concern.

4.2 CRM Tool Attributes

The specific CRM tool and PRA to CRM translation attributes necessary for RMTS implementation are specified in Section 2.3.5. While these CRM attributes may be implemented in various ways at RMTS-implementing stations, these attributes should be verifiable via the approved RMTS program. Guidance and recommendations for each of these attributes is provided as follows:

1. **Initiating events accurately model external conditions and effects of out-of-service equipment.**

   CRM tools should explicitly model external conditions, such as weather impacts, or a process to adequately address the impact of these external conditions exists. The impacts of out-of-service equipment should be properly reflected in CRM initiating event models as well as system response models. For example, if a certain component being declared inoperable and placed in a maintenance status is modeled in the PRA, the entry of that equipment status into the CRM must accommodate risk quantification to include both initiating event and system response impact.

2. **Model truncation levels are adequate to maintain associated decision-making integrity.**

   Model truncation levels applied in the CRM should be such that they have no significant impact on associated RMTS decisions. In general, this means that the truncation levels are such that, for a specific RICT calculation, the RICT calculated via the truncated model would not vary significantly from that calculated via an associated un-truncated model and that important model elements have not been removed from the PRA through truncation. Reference

[8] provides a reasonably rigorous set of criteria for managing PRA model truncation that may be applied for adequate decision-making support.

3. **Model translation from the PRA to a separate CRM tool is appropriate; CRM fault trees are traceable to the PRA. Appropriate benchmarking of the CRM tool against the PRA model shall be performed to demonstrate consistency.**

   No time-averaging features of the model that could lead to configuration-specific errors, such as equipment train asymmetries and treatment of possible alternate configurations, should be included in the CRM Tool. Time-averaging features of the basic event data that could lead to configuration-specific errors should be excluded in the CRM Tool database. Conversely, changes to the model and data should correctly reflect configuration-specific risk. In cases where the CRM tool is simply a configuration risk database cataloguing parameters calculated via the approved PRA, then spot checks of these parameters for conformance with the approved PRA should be performed in accordance with approved station procedures. In cases where the CRM tool directly performs PRA logic model reduction and/or risk calculations, quality assurance checks of the model and quantification results translation from the underlying approved PRA should be performed to validate model translation. These technical adequacy checks should show satisfactory traceability from the CRM model to the approved PRA.

4. **Any modeled recovery actions credited in the calculation of a RICT shall be applicable to the plant configuration.**

   RICT calculations should appropriately account for, and quantify, the impacts of human action dependence relative to plant configurations and conditions analyzed. This is particularly important in cases where credit for RMAs implemented within the RMTS program is taken in the RICT calculation. Performance of human recovery actions modeled in the PRA shall be performed via approved station procedures with the implementing personnel trained in their performance for these actions to be credited in the RMTS program.

5. **Configuration of the plant is correctly mapped from systems / components and real time activities to CRM model parameters.**

   a. Any pre-analysis translation tables from plant activities to CRM Tool basic events or model conditions should be accurate and controlled.

   b. An effective written process should be in place to apply the translation tables and/or generate the CRM Tool inputs corresponding to plant activities.

   c. Training of personnel who apply or review the CRM tool should be performed.

6. **Each CRM application tool is verified to adequately reflect the as-built, as-operated plant, including risk contributors which vary by time of**

year or time in fuel cycle or otherwise demonstrated to be conservative or bounding.

CRM tools should reflect as-built, as-operated plant conditions. The CRM tools should be updated in accordance with approved PRA update procedures.

7. **Application specific risk important uncertainties contained in the CRM model (that are identified via PRA model to CRM tool benchmarking) are identified and evaluated prior to use of the CRM tool for RMTS applications.**

   Uncertainty should be addressed in RMTS CRM tools by consideration of the translation from the PRA model to the CRM tool. Note that the uncertainties evaluated in this step are limited to new uncertainties that could be introduced by application of the configuration management tool to provide or calculate configuration specific risk values used in the determination of a RMAT and RICT. These uncertainties may be evaluated using the same four step process described in Section 3.3.4 to evaluate uncertainties in the PRA base model.

8. **CRM application tools and software are accepted and maintained by an appropriate quality program.**

   CRM application tools and associated software applied for RMTS implementation should meet the same level of quality assurance as the underlying approved PRA software and application tools.

9. **The CRM tool shall be maintained and updated in accordance with approved station procedures to ensure it accurately reflects the as-built, as-operated plant.**

   CRM applications tools and associated software are verified to reflect the as-built, as-operated plant. The CRM tool is maintained and updated in accordance with approved station procedures on a periodic basis not to exceed two refueling cycles. A process for evaluation and disposition of proposed facility changes is established for items impacting the CRM tool with criteria established to require CRM model / tool updates concurrent with implementation for facility changes that potentially can significantly impact RICT calculations. Corrective actions are identified and implemented as soon as practicable to address any identified modeling errors that could significantly impact RICT calculations.

It is recommended that RMTS implementation procedures require that confirmatory checks of RICT assessments and associated calculations by appropriately qualified station staff members be part of the RMTS process. Additionally, station personnel applying CRM tools to perform and approve RICT assessments must be adequately trained and qualified in accordance with station Technical Specifications implementation procedures and the provisions of this guidance.

5 REFERENCES

1. "Risk Managed Technical Specifications (RMTS) Guidelines"; EPRI Report 1011758; December 2005

2. Nuclear Energy Institute, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," NUMARC 93-01, Revision 3, July 2000.

3. "PSA Applications Guide," EPRI Report TR-105396, August 1995.

4. USNRC, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Regulatory Guide 1.174, Revision 1, November 2002.

5. Nuclear Energy Institute, "10 CFR 50.69 SSC Categorization Guideline," NEI 00-04, Final Draft R2, October 2004.

6. "Guideline for the Treatment of Uncertainty in Risk-Informed Applications: Technical Basis Document," EPRI 1009652, Palo Alto, CA, December 2004.

7. "Methodology for Fire Configuration Risk Management," EPRI Report 1012948, December 2005.

8. Cepin, Marko, "Method for Setting up the Truncation Limit of Probabilistic Safety Assessment," International Conference on Probabilistic Safety Assessment and Management (PSAM 7 – ESREL '04) paper 0602, June 2004.

9. Regulatory Issue Summary 2005-20 and NRC Inspection Manual, Part 9900: Technical Guidance, "Operability Determinations and Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety," issued 9/26/05.

A
GLOSSARY OF TERMS

Key terms used in this guide are defined in this appendix. These definitions are intended to be consistent with existing plant Technical Specifications and associated regulatory and industry guidance. In any case where a plant's Technical Specifications definitions differ from those provided herein, the plant Technical Specifications definitions take precedence.

allowed outage time (AOT) – Same as completion time (CT).

back-stop completion time (back-stop CT) – the ultimate LCO completion time or allowed outage time limit permitted by the RMTS. The back-stop completion time limit for licensee action takes precedence over any risk-informed completion time calculated to be greater than 30 days.

baseline risk – the "no-maintenance" or "zero-maintenance" risk calculated via the plant PRA. This is different from (i.e., less than) the average annual risk calculated via the PRA.

completion time (CT) – as defined in the improved standard Technical Specifications (NUREG-1430 through -1434), the completion time is the amount of time allowed by the Technical Specifications for completing an action. Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The actions associated with an LCO state conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated condition are action(s) and completion time(s). The completion time is the amount of time allowed for completing an action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering a condition unless otherwise specified in the Technical Specifications.

configuration risk management (CRM) program – the plant program designed to apply the approved PRA to support prudent risk management over the plant life cycle. This program is designed to support the planning and execution of plant maintenance, testing, and inspection activities, as well as other risk-impacting evolutions.

core damage probability (CDP) – the integral of CDF over time; the classical cumulative probability of core damage (i.e., instantaneous core or fuel damage frequency integrated over a specified duration), over a given period of time. CDP is unit-less. Weekly risk is calculated for the 168-hour time period over each calendar week. Configuration risk is calculated for the anticipated and/or actual duration of a plant configuration. Annual risk is a 52-week rolling average, calculated week by week.

cumulative risk – the accumulated risk integrated over time accounting for variations in instantaneous risk.

emergent event or emergent condition – any event or condition, which is NOT in the planned work schedule, which renders station equipment non-functional or extends non-functional equipment scheduled outage time beyond its planned duration. The term "any event or condition" includes the impacts of mode changes and external conditions which adversely impact the risk associated with the evolution.

front-stop completion time (front-stop CT) – the completion time or allowed outage time for plant equipment specified in the conventional plant Technical Specifications.

high-risk configuration – a plant configuration yielding a plant instantaneous CDF > 1.00E-03 or LERF > 1.00E-4 per year.

incremental core damage frequency (ICDF) – the frequency above a "no-maintenance" baseline CDF (expressed in terms of events per calendar year) that one can expect a reactor fuel core-damaging event to occur for a nuclear power plant of interest.

incremental core damage probability (ICDP) – the integral of ICDF over time; the classical cumulative probability of incremental core damage over a given period of time. ICDP is unit-less. Weekly risk is calculated for the 168-hour time period over each calendar week. Configuration risk is calculated for the anticipated and/or actual duration of a plant configuration. Annual risk is a 52-week rolling average, calculated week by week.

incremental large early release frequency (ILERF) – the frequency above a "no-maintenance" baseline LERF (expressed in terms of events per calendar year) that one can expect a large early release of radioactivity [3] from a reactor core-damaging event to occur for a nuclear power plant of interest.

incremental large early release probability (ILERP) – the classical cumulative probability of incremental large early release of radioactivity over a given period of time. ILERP is unit-less. Weekly risk is calculated for the 168-hour time period over each calendar week. Configuration risk is calculated for the anticipated and/or actual duration of a plant configuration. Annual risk is a 52-week rolling average, calculated week by week.

instantaneous core damage frequency (CDF) – the instantaneous expected core damage frequency resulting from continued operation in a specific plant mode and a given plant configuration (generally presented with units of events/year). This term is very similar to the conventional use of the term "core damage frequency" applied in probabilistic risk assessments. However, for application to RMTS programs, the focus here is on a single point in time, and not on longer term averages typically applied.

instantaneous large early release frequency (LERF) – the instantaneous expected large early release frequency resulting from continued operation in a specific plant mode and a given plant configuration (generally presented with units of events/year). This term is very similar to the conventional use of the term "larger early release frequency" applied in probabilistic risk assessments. However, for application to RMTS programs, the focus here is on a single point in time, and not on longer term averages typically applied.

large early release probability (LERP) – the classical cumulative probability of large early release of radioactivity (i.e., instantaneous large early release frequency integrated over a specified duration), over a given period of time. LERP is unit-less. Weekly risk is calculated for the 168-hour time period over each calendar week. Configuration risk is calculated for the anticipated and/or actual duration of a plant configuration. Annual risk is a 52-week rolling average, calculated week by week.

limiting condition for operation (LCO) – as defined in 10 CFR 50.36 (c)(2), limiting conditions for operation are the lowest operable 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.

operable and operability – as defined in the improved standard Technical Specifications (NUREG-1430 through -1434) a system, subsystem, train, component or device shall be operable or have operability when it is capable of performing its specified function(s), and when all necessary attendant instrumentation, controls, electrical power, cooling and seal water, lubrication and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) are also capable of performing their related support function(s).

operational mode or mode – as defined in the improved standard Technical Specifications (NUREG-1430 through -1434), an operational mode (i.e., mode) shall correspond to any one inclusive combination of core reactivity condition, power level, and average reactor coolant temperature specified in plant Technical Specifications.

plant configuration – the consolidated state of all plant SSCs with their associated individual states of functionality (i.e., either functional or non-functional) and alignment (including surveillance inspections and testing alignments) identified. Consistent with the Maintenance Rule and associated NEI guidance [2], the concept of "plant configuration" encompasses the existence of activities or conditions (including maintenance) that can materially affect plant risk.

In the context of this guide, there are two major types of plant configurations, planned and unplanned. A planned configuration is one that is intentionally and deliberately pre-scheduled (e.g., in a weekly maintenance plan). An unplanned configuration includes an unintentional, emergent situation (i.e., discovery of failure or significant degradation of an SSC with the provision to utilize a RICT or a forced, unscheduled extension of previously-planned maintenance).

PRA-calculated mean value: the mean value of a probability distribution for a key risk measure, such as CDP or LERP, calculated via the PRA.

probabilistic risk assessment (PRA) – a quantitative assessment of the risk associated with plant operation and maintenance that is measured in terms of frequency of occurrence of risk metrics, such as core damage or a radioactive material release and its effects on the health of the public (also referred to as a probabilistic safety assessment, PSA).

PRA functionality - functionality that can be explicitly credited in a RICT calculation of a Technical Specification inoperable SSC.

recovery – restoration of a function lost as a result of a failed SSC by overcoming or compensating for its failure.

repair - restoration of a failed SSC by correcting the cause of failure and returning the failed SSC to its modeled functionality.

risk-informed completion time (RICT) – a plant-specific SSC plant configuration CT calculated based on maintaining plant operation within allowed risk thresholds or limits and applying a formally approved configuration risk management program and associated probabilistic risk assessment. The RICT is the time interval from discovery of a condition requiring entry into a Technical Specifications action for a SSC with the provision to utilize a RICT until the 10^{-5} ICDP or 10^{-6} ILERP threshold is reached, or 30 days, whichever is shorter. The maximum RICT of 30 days is referred to as the "back-stop CT." For the purposes of RMTS implementation, a SSC is considered to be in a RICT when it (1) is Technical Specification inoperable and (2) is beyond its front-stop CT.

risk-management action time (RMAT) - the time interval at which the risk management action threshold is exceeded. Stated formally, the RMAT is the time interval from discovery of a condition requiring entry into a Technical Specifications action for a SSC with the provision to utilize a RICT until the 10^{-6} ICDP or 10^{-7} ILERP RMA threshold is reached, whichever is the shorter duration. This guidance requires risk management actions to be taken no later than the calculated RMAT.

risk-management technical specifications (RMTS) – a plant-specific set of configuration-based Technical Specifications, based on a formally approved configuration risk management program and associated probabilistic risk assessment, designed to supplement previous conventional plant Technical Specifications.

zero-maintenance CDF – the calculated CDF for the zero-maintenance configuration.

zero-maintenance configuration – the plant configuration where no planned or emergent maintenance is being performed (including any risk-impacting testing or inspection actions) and PRA components remain functional.

zero-maintenance LERF – the calculated LERF for the zero-maintenance configuration.

NEI 04-10 (Revision 1)

Risk-Informed Technical Specifications Initiative 5b

Risk-Informed Method for Control of Surveillance Frequencies

Industry Guidance Document

April 2007

ACKNOWLEDGMENTS

NEI wishes to acknowledge the considerable effort made by the following individuals in developing this guidance.

Mr. Visweswaran Srinivasa, General Electric
Mr. Glenn Stewart, Exelon
Mr. Eugene Kelly, Exelon
Mr. Philip Tarpinian, Exelon
Mr. Don Vanover, ERIN
Ms. Victoria Warren, ERIN

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EXECUTIVE SUMMARY

This document provides guidance for implementation of a generic Technical Specifications improvement that establishes licensee control of surveillance test frequencies for the majority of Technical Specifications surveillances. Existing specific surveillance frequencies are removed from Technical Specifications for the affected specifications, and placed under licensee control pursuant to this methodology. A paragraph is added to the Administrative Controls section referencing this methodology document, as approved by NRC, for control of surveillance frequencies. The surveillance test requirements (test methods) are not changed, and remain in the Specifications.

This methodology uses a risk-informed, performance based approach for establishment of surveillance frequencies, consistent with the philosophy of NRC Regulatory Guide 1.174. Probabilistic Risk Assessment (PRA) methods are used to determine the risk impact of the revised intervals. Sensitivity studies are performed on important PRA parameters. PRA technical adequacy is addressed through NRC Regulatory Guide 1.200, which references the ASME PRA standard, RA-S-2005b, for internal events at power. External events and shutdown risk impact may be considered quantitatively or qualitatively.

A multi-disciplinary plant decisionmaking panel is utilized to evaluate determinations of revised surveillance frequencies, based on operating experience, test history, manufacturers recommendations, codes and standards, and other factors, in conjunction with the risk insights from the PRA. Results and bases for the decision must be documented.

The methodology includes guidance on determining the specific surveillance frequencies to which this process is applied, and existing frequencies are retained if the process is not applied. Process elements are included for determining the cumulative risk impact of the changes, updating the PRA, and for imposing corrective actions, if necessary, following implementation.

1.0 INTRODUCTION

This document has been developed to provide the technical methodology to support risk informed technical specifications initiative 5B, which provides a risk-informed method for licensee control of Surveillance Frequencies. The corresponding TSTF 425, Revision 1. relocates the majority of the Technical Specification Surveillance Requirement Frequencies to the licensee-controlled program. The Surveillance Requirements themselves will remain in the Technical Specifications, pursuant to 10 CFR 50.36 (Ref. 1). The Administrative Controls section of the Technical Specifications will specify the requirements for a Surveillance Frequency Control Program (SFCP) that the licensee will use to control Surveillance Frequencies[1] and make future changes to the Surveillance Requirement Frequencies.

Revision 1 to NEI 04-10 is provided to address test strategy (e.g. Staggered Test Basis) in addition to frequency. Under the proposed change, the Frequencies of all Surveillance Requirements (except those that reference other programs for the specific interval or that are event driven) are relocated. The Frequency may include the requirement to perform the Surveillance on a Staggered Test Basis and, therefore, the phrase "on a Staggered Test Basis" is also relocated to licensee control under the Surveillance Frequency Control Program. NEI 04-10 Revision 1 contains new information (Step 12-A1-1) to address how Surveillances which are performed on a Staggered Test Basis are modeled in the risk assessment performed to support a change to the Frequency. This will allow licensees to add or remove the requirement to perform Surveillances on a Staggered Test Basis under the Surveillance Frequency Control Program. Revision 1 also incorporates reference updates and enhancements to appendices.

The Surveillance Frequency Control Program states:

5.5.15 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

[1] The term Surveillance Test Interval (STI) is used in the SFCP change process description to describe the time interval associated with the Surveillance Frequency specified in the Technical Specification. A change to the STI is analogous to a change in the Surveillance Frequency.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, " Risk-Informed Method for Control of Surveillance Frequencies," Revision 0.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

This document provides a risk-informed process and methodology for implementing the SFCP to control the relocated Technical Specification Surveillance Requirement Frequencies for structures, systems and components (SSC). The methodology of this document, once accepted by Nuclear Regulatory Commission, provides the basis for maintaining and changing the Technical Specification Surveillance Frequencies in accordance with the SFCP.

2.0 OVERALL APPROACH

The SFCP shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation (LCOs) are met. Existing regulatory programs, such as 10 CFR 50.65 (Ref. 2; the Maintenance Rule) and the corrective action program required by 10 CFR 50, Appendix B (Ref. 3), require monitoring of Surveillance test failures and require action be taken to address such failures. One of these actions may be to consider changing the Frequency at which a Surveillance is performed. These regulatory requirements are sufficient to ensure that Surveillance Frequencies which are insufficient to assure the LCO is met are identified and action taken. In addition, the SFCP requires monitoring of Surveillance Frequencies that are changed using the process described in this document.

The approach for changing Surveillance Frequencies uses existing Maintenance Rule implementation guidance (NUMARC 93-01, Rev. 3) (Ref. 4), combined with elements of NRC In-service Testing Regulatory Guide (RG) 1.175 (Ref. 5), to develop risk-informed test intervals for SSCs having Technical Specification Surveillance Requirements. Although originally developed to address test intervals for pump and valve testing required by the ASME Code, the concepts of RG 1.175 are applicable to the SFCP with minor modifications. In particular, this Regulatory Guide provides information relative to modeling the effect of the revised Surveillance Frequencies in a probabilistic risk assessment (PRA).

The method described here is also consistent with RG 1.174 (Ref. 6), “An Approach for Using Probabilistic Risk Assessments in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” and RG 1.177 (Ref. 7), “An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specifications” and provides more specific guidelines to facilitate application by the licensee. RG 1.177 provides guidance for changing Surveillance Frequencies and Completion Times. However, for allowable risk changes associated with Surveillance Frequency changes, it refers to RG 1.174. The regulatory guide provides quantitative risk acceptance guidelines for changes to core damage frequency (CDF) and large early release frequency (LERF), along with additional guidelines that have been adapted for this methodology.

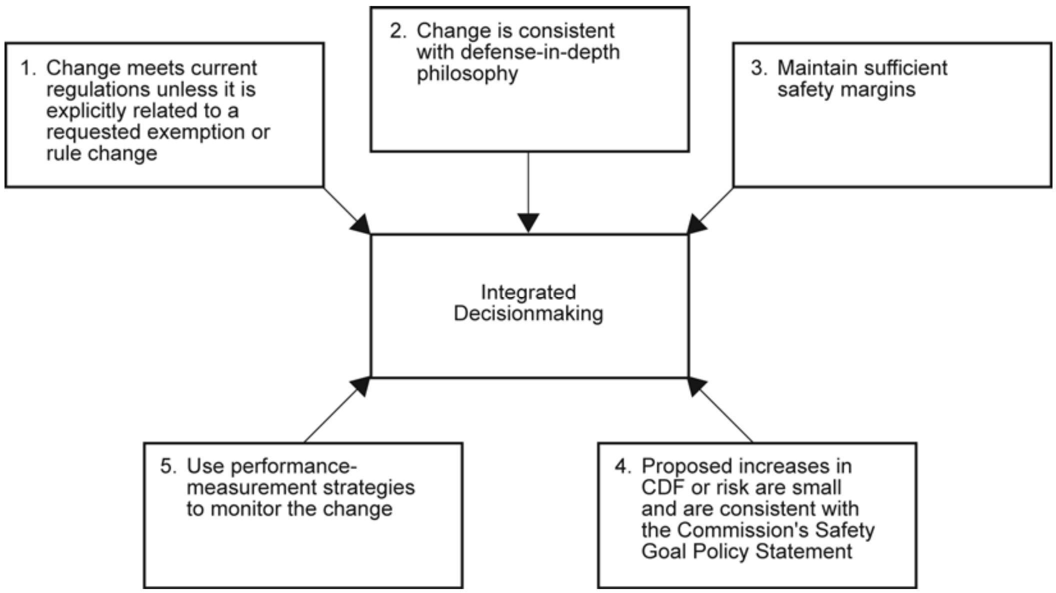
The detailed SFCP process is described in Section 4. PRA technical adequacy will be addressed through NRC RG 1.200 (Ref. 8). Following the establishment of adequate PRA capability, the process involves the development of revised Surveillance Frequencies (i.e., STIs) based on risk insights from PRAs, plant operational experience, and other factors. The effect of the proposed change, aggregate risk impact[2] of the single revised Surveillance Frequency for all PRA events, and the cumulative risk impact for all Surveillance Frequency changes will be compared to NRC risk acceptance guidelines. Feedback and periodic re-evaluation of the Surveillance Frequencies will be conducted for SSCs.

[2] Also referred to as total risk impact in this document.

3.0 KEY SAFETY PRINCIPLES FOR CHANGING FREQUENCIES

RG 1.174 identifies five key safety principles to be met for all risk-informed applications and to be explicitly addressed in risk-informed plant program change applications.

Figure 1 of RG 1.174 illustrates the consideration of each of these principles in risk-informed decision-making.



1. **The proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change.**

   10 CFR 50.36(c) provides that Technical Specifications will include items in the following categories:

   "(3) *Surveillance Requirements*. Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met."

   Technical Specifications Initiative 5B and TSTF-425 propose to relocate the Surveillance Frequencies for most Surveillance Requirements to a licensee-controlled program using an NRC-approved methodology for control of the Surveillance Frequencies. The Surveillance Requirements themselves would remain in Technical Specifications.

   This change is consistent with other NRC-approved TS changes in which the Surveillance Frequencies are not under NRC control, such as Surveillances that are performed in accordance with the In-service Testing Program or the Primary

Containment Leakage Rate Testing Program, where the Frequencies vary based on the past performance of the subject components. Thus, this proposed change meets criterion 1 above.

2. The proposed change is consistent with the defense-in-depth philosophy.

Consistency with the defense-in-depth philosophy is maintained if:

- A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation.
- Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided.
- System redundancy, independence and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties (e.g., no risk outliers).
- Defenses against potential common cause failures are preserved, and the potential for the introduction of new common cause failure mechanisms is assessed.
- Independence of barriers is not degraded.
- Defenses against human errors are preserved.
- The intent of the General Design Criteria in 10 CFR Part 50, Appendix A (Ref. 9) is maintained.

These defense-in-depth objectives apply to all risk-informed applications and, for some of the issues involved (e.g., no over-reliance on programmatic activities and defense against human errors), it is fairly straightforward to apply them to this proposed change. The use of the multiple risk metrics of core damage frequency (CDF) and large early release frequency (LERF) and controlling their change resulting from the implementation of this initiative would maintain a balance between prevention of core damage, prevention of containment failure, and consequence mitigation. Redundancy, diversity and independence of safety systems are considered as part of the risk categorization to ensure that these qualities are not adversely affected. Independence of barriers and defense against common cause failures are also considered in the categorization. The improved understanding of the relative importance of plant components to risk resulting from the development of this program should promote an improved overall understanding of how the SSCs contribute to a plants defense in depth.

3. **The proposed change maintains sufficient safety margins.**

   Conformance with this principle is assured with proposed changes to Surveillance Frequencies since the SSC design, operation, testing methods, and acceptance criteria specified in applicable Codes and Standards, or alternatives approved for use by the NRC, will continue to be met as described in the plant licensing basis (e.g., FSAR, or Technical Specifications Bases). Also, the safety analysis acceptance criteria in the plant licensing basis (e.g., FSAR, supporting analyses) will continue to be met with the proposed changes to Surveillance Frequencies.

4. **When proposed changes result in an increase in core damage frequency or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.**

   In the SFCP, the overall impact of the change is assessed and compared to the quantitative risk acceptance guidelines of RG 1.174, which is consistent with the intent of the Commission's Safety Goal Policy Statement. Two types of effects on CDF and LERF are considered. The first effect involves the total or aggregate risk impact for all PRA events for each individual Surveillance Frequency change. The second effect involves the cumulative risk impact from all Surveillance Frequency changes. More detail is provided in subsequent paragraphs that describe the SFCP process. The PRA used to support this change will, at a minimum, address CDF and LERF for power operation. External event risk and shutdown considerations will be addressed through quantitative or qualitative means.

   NRC RG 1.200 addresses technical adequacy of PRA for risk-informed applications. This regulatory guide will be followed for plants proposing to implement Initiative 5B through TSTF-425 and the SFCP.

5. **The impact of the proposed change should be monitored using performance measurement strategies.**

   A performance monitoring strategy will be developed to provide confidence that the equipment performance is consistent with the considerations of the overall SFCP process, and is not degrading such that the analysis assumptions and expert panel judgments are no longer valid. For certain cases, existing performance monitoring required by the Maintenance Rule is adequate for SSCs whose Surveillance Frequencies are controlled under the SFCP. The output of the performance monitoring will be periodically re-assessed, and appropriate adjustments made to the Surveillance Frequencies.

4.0 SURVEILLANCE FREQUENCY CONTROL PROGRAM CHANGE PROCESS

The SFCP change process is shown in flow diagrams in the Figures 1, 2 and 3. The process steps are described below:

Step 0: Select Proposed STIs for Adjustment

The initial step in the SFCP change process is to select proposed surveillance test intervals (STIs) for adjustment. STIs may need to be adjusted as a required action in response to monitoring surveillance test failures in accordance with 10 CFR 50.65 (the Maintenance Rule) and the corrective action program required by 10 CFR 50, Appendix B. In addition, STIs may be adjusted to realize specific benefits. Inputs to the selection of STIs for adjustment should be obtained from various site organizations, such as, Operations, Outage Management, Work Management, Health Physics, Licensing, and Engineering. The following is a representative list (not inclusive) of potential factors/benefits that should be considered in identifying candidate STIs for adjustment:

1. Safety risk
2. Reactivity management.
3. Maintaining dose as low as reasonably achievable (ALARA).
4. Burden reduction, including consideration of cost of the test (resources).
5. Outage impact (outage work control).
6. Work management simplification (on-line work control).
7. Production risk.
8. Reducing wear and tear on the SSC.
9. Reducing potential for test-caused errors.
10. Difficulty of the test and potential for error during the test and its consequence.
11. Consideration of the role of the test on the reliability of the associated function.
12. Maintenance Rule A1 item that has an associated action plan that necessitates more frequent testing.
13. Maintenance Rule and the associated corrective action process that necessitates more frequent testing.

In addition, for an STI previously extended through the Surveillance Frequency Control Program, the minimum number of surveillance intervals required to establish an adequate database for further extending the STI shall be as follows:

(1) a minimum of three successive satisfactory performances of the surveillance where the STI is less than or equal to six months, or

(2) a minimum of two successive satisfactory performances of the surveillance where the STI is greater than six months.

NOTE: The criteria provided above do not apply to phased implementation. If phased implementation is used, the schedule for the phased implementation is recommended based on the results of the evaluation (Step 15) and is approved by the Independent Decisionmaking Panel (IDP) as part of their approval of the proposed STI change (Step 16).

Step 1: Check for Prohibitive Commitments

In Step 1, all the commitments made to the NRC are collected and reviewed. Some of the commitments to maintain a certain surveillance test interval may have been made in relation to certain other plant issues. As part of this step, such commitments are identified and then, in Step 2, the commitments are examined to determine if they can be changed. If there are no such commitments, then the STI change process continues in Steps 5 and 6.

Step 2: Can Commitments be Changed?

In Step 2, a check is made to determine if the NRC commitments can be changed. Evaluating changes to the NRC commitments is a separate activity based on a method acceptable to the NRC for managing and changing regulatory commitments, e.g., NEI 99-04 (Ref. 10). If the commitments can be changed without prior NRC approval, go to Step 3 for changing the commitments. If the commitments cannot be changed without prior NRC approval, go to Step 4.

Step 3: Change the Commitments

In Step 3, change the commitments using a method acceptable to the NRC, e.g., NEI 99-04, such that the STI can be revised using the SFCP process. Return to the SFCP process after the commitments have been changed and continue the SFCP process with Steps 5 and 6.

Step 4: Document that STI Changes Cannot be Changed

This step is entered if, in Step 2, it is determined that the commitment related to a certain STI cannot be changed. Document that the STI cannot be changed and the process concludes here.

Alternatively, Step 4 is entered if PRA or qualitative analyses result in the STI change being unacceptable. In that case, the reasons that the STI change is not acceptable should also be documented and the process concludes here for the specific STI being investigated.

Step 5: RG 1.200 PRA Technical Adequacy

NRC has developed a regulatory guidance for trial use to address PRA technical capability. This is RG 1.200 (Ref. 8), which addresses the use of the ASME PRA standard (Ref. 11), and the NEI peer review process (NEI 00-02; Ref. 12) for evaluating PRA technical capability.

RG 1.200 also provides (or will provide) attributes of importance for risk determinations relative to external events, seismic, internal fires, and shutdown.

Plants implementing TSTF-425 shall evaluate their PRAs in accordance with this regulatory guide. The RG specifically addresses the need to evaluate important assumptions that relate to key modeling uncertainties (such as reactor coolant pump seal models, common cause failure methods, success path determinations, human reliability assumptions, etc). Further, the RG addresses the need to evaluate parameter uncertainties and demonstrate that calculated risk metrics (e.g., CDF and LERF) represent mean values. The identified "Gaps" to Capability Category II requirements from the endorsed PRA standards in the RG and the identified key sources of uncertainty serve as inputs to identifying appropriate sensitivity cases in Step 14 below.

Step 6: Select Desired Revised STI Values

Earlier in Step 0, Technical Specifications STIs are identified for adjustment. This identification is done based on a number of factors, which among others include, the difficulty of the test, cost of the test, potential for error during the test and its consequence, and the role of the test on the reliability of the associated function. As part of Step 6, the licensee should identify the desired revised STI values and any change to the test strategy. In general, the next logical STI given in technical specifications is chosen for improvement. For example, an STI of one month would be changed to quarterly, quarterly to semi-annual, semi-annual to annual, etc. If a STI was chosen which goes beyond the next logical interval, a phased implementation would probably be more appropriate and would need to be considered in Step 15.

Following this step, the SFCP process diverges into two paths, both of which need to be followed. One path, starting at Step 7 performs a qualitative evaluation and the other path, starting at Step 8 leads to a quantitative evaluation. Both paths converge later at Step 15.

Step 7: Identify Qualitative Considerations to be Addressed

Qualitative considerations are developed as an input to the IDP. Such considerations include, but are not limited to:

- Surveillance test and performance history of the components and system associated with the STI adjustment.

- Past industry and plant-specific experience with the functions affected by the proposed changes.

- Impact on defense-in-depth protection.

- Vendor-specified maintenance frequency.

- Test intervals specified in applicable industry codes and standards, e.g., ASME, IEEE, etc.

    - Document that a review of both the committed and current version of applicable industry codes and standards was performed.

    - Any deviations from STIs specified in applicable industry codes and standards currently committed to in the plant licensing basis shall be reviewed and documented consistent with the considerations specified within this step (Step 7).

- Impact of a SSC in an adverse or harsh environment.

- Benefits of detection at an early stage of potential mechanisms and degradations that can lead to common cause failures.

- Document that assumptions in the plant licensing basis would not be invalidated when performing the surveillance at the bounding interval limit for the proposed STI change. For example, if the assumptions in the plant licensing basis would be invalidated at the bounding STI, the STI could be limited accordingly or a more conservative acceptance criteria could be established, as appropriate.

- The degree to which the surveillance provides a conditioning exercise to maintain equipment operability, for example, lubrication of bearings or electrical contact wiping (cleaning) of built up oxidation, and limit the STI accordingly.

- The existence of alternate testing of SSCs affected by the STI change.

The above list of qualitative considerations is not intended to be a complete list. The System Engineering Team will add other qualitative consideration based on their expertise, knowledge of the specific SSC under consideration, and past experience. The IDP in their review of the STI change follows through these qualitative considerations.

The qualitative considerations are summarized and documented in Step 15 and presented to the IDP (Step 16) along with the quantitative considerations from Step 14 and qualitative or bounding analyses from Steps 10a, 10b, and 10c.

Step 8: Associated STI SSC Modeled in PRA?

(Note: Parts of the discussion in Step 10 relating to initial assessments of various types of PRAs is applicable here also. It was included in Step 10 for ease of presentation).

In Step 8, check if the surveillance or the associated systems, or components, are modeled in the PRA. At this point, the focus is on the full power internal events PRA, although the question is applicable for external events PRA and shutdown PRA as well.

In general, the failure probability values of components used in PRAs consist of a time-related contribution (i.e. the standby time-related failure rate) and a cyclic demand-related contribution (i.e. the demand stress failure probability). The risk impact of a proposed STI adjustment shall be calculated as a change of the test-limited risk (see Regulatory Guide 1.177, Section 2.3.3). Since the test-limited risk is associated with failures occurring between tests, the failure rate that shall be used in calculating the risk impact of a proposed STI adjustment is the time-related failure rate associated with failures occurring while the component is in standby between tests (i.e. risk associated with the longer time to detect standby-stress failures). Therefore, caution should be taken in dividing the failure probability into time-related and cyclic demand-related contributions because the test-limited risk can be underestimated when only part of the failure rate is considered as being time-related while this may not be the case. Thus, if a breakdown of the failure probability is considered, it shall be justified through data and/or engineering analyses. When the breakdown between time-related and demand-related contributions is unknown, all failures shall be assumed to be time-related to obtain the maximum test-limited risk contribution.

In practice, to assess if the STI change can be adequately characterized by the PRA the following actions shall be taken:

- Determine all components that are uniquely impacted by the proposed STI change. That is, develop a list of components that are only exercised by the test such that their test-limited risk contribution would be directly affected by the STI change. Establish that the PRA modeled components sufficiently represent the components uniquely impacted by the proposed STI change.

- Determine an appropriate time-related failure contribution for the all of the components to be analyzed as identified in the previous step. The time-related failure contribution can be based on recognized data sources or plant-specific data. If neither is available, then as indicated above, the total failure probability shall be assumed to be time-related.

- Ensure that the model includes appropriate common cause failure terms for the components that are uniquely impacted by the STI change.

If all three of the conditions are appropriately included in the PRA model, then proceed to Step 12 to perform the Total and Cumulative CDF and LERF evaluation for the revised STI values. If the base PRA model does not appropriately address one or more of the three pre-conditions, then proceed to Step 9.

Step 9: Can STI Be Modeled in PRA?

Step 9 is entered from Step 8 if it is determined that the systems or components associated with the STI are not adequately included in the base PRA model. In this step, the analyst has to decide if the STI can be adequately characterized in the PRA model. The determination pertains to all PRAs, including external events and shutdown, but the initial focus is on the internal events PRA.

If it is determined that the STI can be adequately modeled in the PRA with some revisions, proceed to Step 11. Otherwise, proceed to Step 10.

Step 10: Perform Qualitative or Bounding Risk Analysis

(Note: A detailed account of how to approach the various types of PRAs, (internal events, external events and shutdown), is given as part of descriptions provided in this step. Portions of the descriptions are applicable only to Step 8 described earlier. However, they have been included here for a more cohesive presentation.).

Step 10 is entered from Step 9 when it is determined that the STI change cannot be modeled in the plant PRA. In such a case, the PRA analyst will have to perform qualitative or bounding analysis that would provide some indication of the impact of the STI change on the results. A qualitative analysis would involve no use of numerical values in the assessments, whereas a bounding analysis would involve some use of numerical values in the assessment. To account for the potential different approaches and the special considerations associated with the different risk contributors, this step has been subdivided to provide further clarification.

Overview of Initial Assessments

An initial qualitative evaluation can be performed at the system/structure level. If the system/structure is found to have a role in a particular portion of the plant's risk profile, then a component level evaluation can be performed. This qualitative assessment must be performed for all risk contributors (internal events, external events, and shutdown), and the STI change must still be assessed for other considerations (see Step 7) and presented to the IDP.

Some guidelines for performing initial assessments for each of the risk contributors are given below. The results of the assessment will lead to one of the following outcomes:

1. The qualitative information is sufficient for presentation to the IDP.
2. The assessment confirms the conclusion in Step 8 that the STI change can be evaluated in the PRA(s) and the evaluation continues in Step 12.
3. The assessment results in the identification of potential contributors that become candidates for bounding analysis (refer to Steps 10b and 10c).
4. Depending on the outcome from the bounding analysis in Steps 10b and 10c, there is also the potential that more detailed modeling could be desirable to perform an appropriate evaluation of the STI change. In that case, the process would refer back to Step 11 to revise the PRA as needed to perform the detailed assessment.

Initial Assessment for Internal Events

If an SSC is involved in the prevention or mitigation of severe accidents, then the first risk contributor evaluated is from the internal events PRA. The question of whether an SSC is evaluated in the internal events PRA (or any of the analyses considered in this guideline) must be answered by considering not only whether it is explicitly modeled in the PRA (i.e., in the form of basic event(s) – see Step 8), but also whether it is implicitly evaluated in the model through operator actions, super components or another aggregated events sometimes used in PRAs. The term “evaluated” means:

- Can its failure contribute to an initiating event?

- Is it credited for prevention of core damage or large early release?

- Is it necessary, for another system or structure evaluated in the PRA, to prevent an event or mitigate an event?

PRA personnel knowledgeable in the scope, level of detail, and assumptions of the plant-specific PRA shall make these determinations. Certain SSCs are implicitly modeled in the PRA. By examining the attributes listed above, it is possible to address even implicitly modeled components. If in Step 8, the SSC was determined to be explicitly modeled and evaluated in the internal events PRA, then the internal event evaluation process is used to determine the acceptability of the STI change as depicted in Step 12. However, if it is determined that the SSC is only implicitly modeled, then there is a choice of performing either a bounding analysis as described in Step 10b or a detailed analysis as described in Step 11.

If the SSC is not evaluated in the internal events PRA (either explicitly or implicitly, and it is judged to have no impact on the PRA results), then the SSC can be qualitatively screened with the information summarized in Step 15 for presentation to the IDP. This initial screening is from the standpoint of internal events as not having an impact on the CDF and LERF metrics. The evaluation is continued with fire risk.

Initial Assessment for Fire Events

If the plant has a fire PRA, then the next step of the screening process is to determine whether the SSC is evaluated in the fire PRA. (The term "evaluated" is explained above under discussion of internal events). In making this determination, specific attention should be given to structures and the role they play as fire barriers in the fire PRA. PRA personnel knowledgeable in the scope, level of detail, and assumptions of the plant-specific fire PRA shall make the determinations with respect to fire PRAs. If in Step 8, the SSC is determined to be explicitly modeled and evaluated in the fire PRA, then the fire PRA evaluation process is used to determine the fire risk metric inputs associated with the STI change as depicted in Step 12. However, if it is determined that the SSC is only implicitly modeled, then there is a choice of performing either a bounding analysis as described in Step 10b or a detailed analysis as described in Step 11.

If the plant does not have a fire PRA, then a fire risk evaluation, such as the EPRI Fire Induced Vulnerability Evaluation (FIVE) that was performed in response to IPEEE may be used for the evaluation or an application-specific fire analysis can be performed. Again, it is important that personnel knowledgeable in the scope, level of detail, and assumptions of the fire risk evaluation (FIVE) make these determinations. If in Step 8 the SSC is determined to be explicitly modeled and evaluated in the FIVE analysis, then the FIVE process may be utilized to determine the acceptability of the STI change as depicted in Step 12 or an application-specific fire analysis can be performed.

If the SSC is determined to be only implicitly modeled in the FIVE methodology process, then there is a choice of performing either a bounding analysis as described in Step 10b or a detailed analysis as described in Step 11. Because FIVE is a conservative screening analysis, care should be exercised in adding the risk increase values from FIVE evaluation to the total increase from all other PRA results.

If the SSC is not evaluated in either the fire PRA or FIVE evaluations, (either explicitly or implicitly, and it is judged to have no impact on the PRA results), then the SSC can be qualitatively screened with the information summarized in Step 15 for presentation to the IDP. This initial screening is from the standpoint of fire events as not having an impact on the CDF and LERF metrics. The evaluation is continued with seismic risk.

Initial Assessment for Seismic Events

If the plant has a seismic PRA, then the next step of the screening process is to determine whether the SSC is evaluated in the seismic PRA. (The term "evaluated" is explained above under discussion of internal events). Often, structures are explicitly modeled in seismic PRAs. Again, PRA personnel knowledgeable in the scope, level of detail, and assumptions of the plant specific seismic PRA shall make these determinations. If the SSC is determined to be explicitly modeled and evaluated in the seismic PRA, then the seismic PRA evaluation process is used to determine the seismic risk metric inputs of the STI change as depicted in Step 12. However, if it is determined that the SSC is only implicitly modeled, then there is a choice of performing either a bounding analysis as described in Step 10b or a detailed analysis as described in Step 11.

If the plant does not have a seismic PRA, then a seismic risk evaluation, such as a seismic margins analysis (SMA) that was performed in response to the IPEEE may be used for the evaluation. Steps 8 and 9 are not applicable for this case. Personnel knowledgeable in the scope, level of detail, and assumptions of the SMA shall determine the seismic importance. If the SSC structure is included in the SMA, then qualitative information must be developed that supports the acceptability of the STI change with respect to the seismic risk (go to Step 10a).

If the SSC is not evaluated in the seismic PRA, (either explicitly or implicitly, and it is judged to have no impact on the PRA results), or not evaluated in the SMA (either explicitly or implicitly), then the SSC can be qualitatively screened with the information summarized in Step 15 for presentation to the IDP. The evaluation is continued with other external events risk.

Initial Assessment for Other External Events

If the plant has a PRA that evaluates other external hazards, then the next step of the screening process is to determine whether the SSC is evaluated in the external hazards PRA. (The term "evaluated" is explained above under discussion of internal events). Often, structures are explicitly modeled in external hazards PRAs. Personnel knowledgeable in the scope, level of detail, and assumptions of the external hazards PRA shall make these determinations. If the SSC is determined to be explicitly modeled and evaluated in the external hazards PRA, then the external hazards PRA evaluation process is used to determine the external hazards risk metric inputs of the STI change as depicted in Step 12. However, if it is determined that the SSC is only implicitly modeled, then there is a choice of performing either a bounding analysis as described in Step 10b or a detailed analysis as described in Step 11.

If the plant does not have an external hazards PRA, then it is likely to have an external hazards screening evaluation that was performed to support the requirements of the IPEEE. Once again, personnel knowledgeable in the scope, level of detail, and assumptions of the external hazards analysis shall make these determinations. If the SSC is evaluated in the external hazards analysis, then qualitative information must be developed that supports the acceptability of the STI change with respect to the external hazards risk for consideration in Step 10a. If the SSC is not involved in either an external hazards PRA or external hazards screening evaluation, then the SSC can be screened qualitatively with the information presented to the IDP. This initial screening is from the standpoint of external hazards risk as not having an impact on the CDF and LERF metrics. The evaluation is continued with shutdown risk.

Initial Assessment for Shutdown Events

If the plant has a shutdown PRA, then the next step of the screening process is to determine whether the SSC is evaluated in the shutdown PRA. (The term "evaluated" is explained above under discussion of internal events). Personnel knowledgeable in the scope, level of detail, and assumptions of the shutdown PRA shall make the determination. If the SSC is explicitly modeled and evaluated in the shutdown PRA, then the shutdown PRA evaluation process is used to determine the external hazards risk metric inputs of the STI change as depicted in Step 12. However, if it is determined that the SSC is only implicitly modeled, then there is a choice of performing either a bounding analysis as described in Step 10b or a detailed analysis as described in Step 11.

If the plant does not have a shutdown PRA, then it is likely to have a shutdown safety program developed to support implementation of NUMARC 91-06 (Ref. 13) and, if so, this may be used for the evaluation, or application-specific shutdown analysis may be performed. Once again, personnel knowledgeable in the scope, level of detail, and assumptions of the NUMARC 91-06 program shall make this determination. If the SSC is determined to be credited in the NUMARC 91-06, then qualitative information must be developed that supports the acceptability of the STI change with respect to the shutdown risk for consideration in Step 10a.

If the SSC is not involved in a shutdown PRA or NUMARC 91-06, then the SSC can be screened qualitatively with the information presented to the IDP. This initial screening is from the standpoint of shutdown risk as not having an impact on the CDF and LERF metrics.

Step 10a: Qualitative Analysis Sufficient for IDP?

This step is performed to determine if qualitative information is sufficient to provide confidence that the net impact of the STI change would be negligible (or zero) from a CDF and LERF perspective. It is recognized that in certain cases, such as a SMA, qualitative analysis is the only evaluation that can be performed.

For each risk contributor as determined in the initial assessments performed in Step 10 above, if the qualitative information is deemed sufficient, then proceed to Step 15 and provide the basis for the qualitative conclusions to the IDP. Since only qualitative considerations are provided in this case, the impacts of the STI change are not incorporated into the cumulative impacts described in Step 12.

However, if the qualitative information is not deemed sufficient for each contributor, then proceed to Step 10b to perform a bounding analysis as required.

If the seismic risk was evaluated using the SMA, then, in the SMA, a determination shall be made if the SSC impacted by the STI change is part of the success path or not, and the information conveyed to the IDP in Step 15. Similarly, if the plant had performed other external hazards analysis or a NUMARC 91-06 safety program for shutdown risk, a qualitative evaluation shall be made by personnel knowledgeable in the scope, level of detail, and assumptions of the analysis to conclude if the SSC impacted by the STI change has an important contribution in the evaluation, and the information conveyed to the IDP in Step 15.

Step 10b: Bounding Analysis Below 1E-07/yr CDF and 1E-08/yr LERF?

This step is performed to provide bounding impacts from the STI change if the qualitative considerations alone were deemed insufficient to bring to the IDP.

As an example, bounding analysis is performed for those SSCs that are not explicitly modeled in the PRA model, but rather are implicitly included in the model at the initiating event, mitigating system, or functional level. In that case, a basic event (or basic events) associated with the initiating event, mitigating system, or function is identified to use as surrogate for the SSC to be investigated. Reasonable variations to the basic event value(s) should then be explored to determine the potential bounding impact of the STI change.

Alternative evaluations for the impact from external events and shutdown events are also deemed acceptable at this point. For example, if the ΔCDF and ΔLERF values have been demonstrated to be very small from an internal events perspective based on detailed analysis of the impact of the SSC being evaluated for the STI change, and if it is known that the CDF or LERF impact from external events (or shutdown events as applicable) is not specifically sensitive to the SSC being evaluated (by qualitative reasoning), then the detailed internal events evaluations and associated required sensitivity cases (as described in Step 14) can be used to bound the potential impact from external events and shutdown PRA model contributors. As an another example, if the ΔCDF and ΔLERF values have been demonstrated to be very small from an internal events perspective based on detailed analysis of the impact of the SSC being evaluated for the STI change, and if it is known that the plant CDF and LERF results of the external event or shutdown PRA are much smaller than the corresponding values for the internal event full power PRA, (that is, less than 10%), then the results of the internal events analysis alone would suffice for the STI consideration. This example is likely to be applicable for a situation where the SSC associated with the STI change is modeled in the internal event full power PRA, but not in the external event or shutdown PRA.

If the bounding analysis indicates that the ΔCDF and ΔLERF evaluation is below the 1E-07/yr CDF and 1E-08/yr LERF limits, then proceed to Step 15 and provide the results of the bounding analysis to the IDP. However, since the STI is not directly modeled in the PRA but the bounding analysis shows that the impact of the STI change is negligible, then the impacts of the STI change are not incorporated into the cumulative impacts described in Step 12.

If the bounding analysis does not indicate that the STI change is below the 1E-07/yr CDF and 1E-08/yr LERF limits, consider a revised STI value and proceed to Step 10c.

Step 10c: Revised STI Values Allow Bounding Analysis Below 1E-07/yr CDF and 1E-08/yr LERF?

It is not anticipated that this step will be answered in the affirmative too often, but is provided for completeness. This step is entered if the bounding analysis indicates that the results are not below the 1E-07/yr CDF and 1E-08/yr LERF limits at the desired STI value, but could be below the limits if a reduced STI value is attempted. If it is appropriate, at this stage, the PRA model can be refined to help model the STI change more explicitly than in the original model.

If the revised bounding analysis indicates that the STI change is below the 1E-07/yr CDF and 1E-08/yr LERF limits, then proceed to Step 15 and provide the results of the bounding analysis performed in Steps 10b and 10c to the IDP. However, since the STI is not directly modeled in the PRA but the bounding analysis shows that the impact of the STI change is negligible, then the impacts of the STI change are not incorporated into the cumulative impacts described in Step 12.

If the revised bounding analysis does not indicate that the STI change is below the 1E-07/yr CDF and 1E-08/yr LERF limits, then proceed to Step 4, document that the STI cannot be changed and stop. Alternatively, detailed modeling could be performed to more accurately reflect the CDF and LERF impacts from the STI change. In that case, proceed to Step 11 to revise the PRA as needed to perform a more detailed assessment.

Step 11: Revise PRA Model as Needed

Step 11 is entered from Step 9 when it is determined that the STI change can be modeled in the PRA, but some revisions are required, or from Step 10 when bounding analysis are not sufficient to support the STI change request. In either case, the following actions are required:

- Modify the PRA model as required to ensure that it includes adequate representations of the items identified in Step 8.
- If necessary, re-establish base case CDF and LERF values based on the current STI values for the affected components.

Upon completion of this step, one proceeds to Step 12 to perform the Total and Cumulative CDF and LERF evaluation for the revised STI values.

Step 12: Evaluate Total and Cumulative Effect on CDF and LERF (See Figure 2)

In Step 12, two types of effects on CDF and LERF are considered from all PRAs (internal events, external events, and shutdown). The first effect involves the total change to CDF/LERF results from all PRAs for individual STI changes, and the second effect involves the cumulative CDF/LERF change from all STI changes. These are described below.

a) For each individual STI analyzed, total change in CDF/LERF for all PRAs (i.e., internal events, external events, and shutdown events), shall be less than an acceptance criterion of 1E-06/yr for CDF and 1E-07/yr for LERF. These ΔCDF and ΔLERF values are carried forward to b) where the cumulative change of all STI changes is considered.

   However, as shown in Step 12-B2, where conservative or bounding estimates of CDF/LERF are used for external events or shutdown events, if it can be reasonably shown that that the ΔCDF or ΔLERF contribution for external events or shutdown events is less than 1E-07/yr for CDF and 1E-08/yr for LERF, the change in CDF/LERF from STI changes for external events or shutdown events need not be considered further.

b) For a cumulative change in CDF/LERF resulting from all STI changes using SFCP, from a baseline starting point, an acceptance criterion of 1E-05/yr for CDF and 1E-06/yr for LERF will apply. In addition, the total CDF must be reasonably shown to be less than 1E-04/yr when using the 1E-05/yr ΔCDF criterion. Similarly, the total LERF must be reasonably shown to be less than 1E-05/yr when using the 1E-06/yr ΔLERF criterion. These acceptance criteria are consistent with RG 1.174.

Figure 2 illustrates this process. Steps A and B are performed in parallel to examine the impacts from the internal events at power PRA model (Step 12-A) as well as the external events and shutdown PRA models (Step 12-B) as applicable.

Step 12-A1: Calculate the ΔCDF and ΔLERF values from the Internal Events PRA

This step involves exercising the internal events PRA model as addressed in Step 8 or Step 11. The process involves the following:

- Adjust the time-related failure contribution for the all of the components that are uniquely impacted by the STI change. As indicated in Step 8, the time-related failure contribution can be based on recognized data sources or plant-specific data. If neither is available, the total failure probability shall be assumed to be time-related.

- Adjust the common cause failure (CCF) terms for the components that are uniquely impacted by the STI change. Unless justified otherwise, this adjustment shall be proportional to the adjustment made for the independent time-related contributions to the total independent failure probability.

- Re-evaluate the CDF and LERF values based on the revised independent and CCF failure probabilities identified above. Use the revised CDF and LERF values to determine the ΔCDF and ΔLERF values for the contribution from the internal events model in Step 12-A2.

Step 12-A1-1: Address the Test Strategy

Note that this section only needs to be applied if it is desired to remove or add a staggered test basis requirement, or to otherwise evaluate the differences between staggered or sequential test strategies.

This step involves an evaluation of the test strategies for performing the surveillance (e.g., staggered or sequential testing for redundant components or trains). The timing of surveillance tests for redundant components relative to each other (i.e., the test strategy used) has an impact on the risk measures calculated. The risk impacts of adopting different test strategies (e.g., sequential vs. staggered) can be evaluated to determine whether there is an impact on the evaluation of the change being considered. For example, NUREG/CR-6141 (Ref. 15) provides the following formulas for two redundant components' unavailability contributions for different test strategies.

$Q_2 = 1/4\ \lambda^2\ T^2$ **Independent testing**

$Q_2 = 1/3\ \lambda^2\ T^2$ **Sequential testing**

$Q_2 = 5/24\ \lambda^2\ T^2$ **Staggered testing**

Where Q_2 is the unavailability contribution, λ is the failure rate, and T is the test interval. It should be noted that without making specific adjustments to the

PRA model, the random failures are typically treated as independent (i.e. two terms of $\lambda T/2$ that appear in the same cutsets will yield results equivalent to the independent testing Q_2 expression provided above of 1/4 $\lambda^2 T^2$). As can be seen from the other example expressions above for random failures, a staggered testing strategy (i.e., with tests performed at evenly spaced intervals between the redundant component trains) is expected to yield slightly lower contributions compared to the random independent contribution, and a sequential testing strategy (i.e., tests performed at approximately the same time for all of the redundant component trains) are expected to yield slightly higher contributions compared to the random independent contribution. Similar results are also obtained for groups of three or four as provided in NUREG/CR-6141.

The combination of random failure contributions, however, will typically be negligible if corresponding common cause failure (CCF) terms are also included in the model (as required in Step 8 of this methodology). In the cases where staggered versus sequential testing strategies are being considered, the difference on the common cause failure contribution can also be evaluated. For example, NUREG/CR-5497 (Ref. 16) provides the following formulas for determining the common cause failure probability associated with two redundant components for different test strategies.

$CCF_2 = \alpha_2 Q_T$ **Staggered Testing**

$CCF_2 = 2\alpha_2 Q_T / \alpha_t$ **Non-staggered Testing**

Where Q_T is the total failure probability (derived from $\lambda T/2$ in this case) and the α terms represent the alpha factor CCF parameters for the redundant components in question. NUREG/CR-5497 also provides similar formulas for common cause group sizes up to six. In any event, the evaluation of different test strategies should incorporate the different CCF formulas (i.e.. staggered versus non-staggered testing) to determine the impact on the STI change assessment. Sufficient basis must also exist for the alpha factors used in the assessment if the "on a staggered test basis" requirement is to be removed for the STI in question. Otherwise, it is recommended that the staggered test basis requirement remain.

Step 12-B1: ΔCDF and ΔLERF Insignificant Based on Qualitative Analysis?

This step involves performing a qualitative assessment of the potential impact on CDF and LERF from external events and shutdown PRAs. The guidance provided in Step 10 for performing qualitative assessments should also be utilized here.

For each contributor (e.g. fire, seismic, shutdown) where it can be qualitatively determined that the net impact of the STI change is negligible, one can proceed to Step 12-A2 without including its contribution to the total CDF and LERF impact. For each contributor where it cannot be qualitatively determined that the net impact of the

STI change is negligible, the analyst must proceed to Step 12-B2 to perform a bounding analysis.

Step 12-B2: ΔCDF and ΔLERF Below 1E-07/yr CDF and 1E-08/yr LERF Based on Bounding Analysis?

This step is entered from Step 12-B1 if a qualitative determination was not sufficient to establish that the net impact on CDF and LERF is negligible from the STI change. In this case, an initial bounding analysis of the impact from external events and shutdown can be considered. The guidance provided in Step 10b for performing bounding analysis should also be utilized here. Alternatively, the use of conservatively biased external events or shutdown PRA models is also deemed sufficient for this step.

For each contributor (e.g., fire, seismic, shutdown) where conservative or bounding analysis can be utilized to determine that the net impact of the STI change is less than 1E-07/yr for ΔCDF and 1E-08/yr for ΔLERF, one can proceed to Step 12-A2 without including its contribution to the total CDF and LERF impact. For each contributor where conservative or bounding analysis cannot be utilized to determine that the net impact of the STI change is less than 1E-07/yr for ΔCDF and 1E-08/yr for ΔLERF, the analyst must proceed to Step 12-B3 to refine the analysis if possible. In any event, any contributors to CDF and LERF from external events or shutdown that do not screen out at Step 12-B1 or 12-B2 shall be included in the total impact assessment in Step 12-A2.

Step 12-B3: ΔCDF and ΔLERF Below 1E-06/yr CDF and 1E-07/yr LERF Based on Refined Analysis?

This step is entered from Step 12-B2 if conservative or bounding analysis does not show that the net impact of the STI change is less than 1E-07/yr for ΔCDF and 1E-08/yr for ΔLERF. At this point, refinement to the conservative or bounding analysis may be pursued since the impact will be included in the total impact assessment in Step 12-A2. The degree of margin and the ability to adequately characterize the impact will determine the amount of refinement that is done.

The final ΔCDF and ΔLERF values calculated from this step must be compared against the criterion of 1E-06/yr for CDF and 1E-07/yr for LERF. If the criteria are met, then the increase in CDF and LERF values calculated in this step must be added to the corresponding other PRA contributors in Step 12-A2. If the CDF and LERF criteria are not met, then proceed to Step 13 to consider a revised surveillance test interval for re-evaluation in Step 12 or to Step 4 to end the process.

Step 12-A2: Calculate Total Effect on CDF and LERF for Individual STI Change

This step simply involves summing the ΔCDF and ΔLERF values determined in Step 12-A1 and in Step 12-B3 (if applicable). These values are utilized to see if the total CDF and LERF change is within RG 1.174 limits of 1E-06/yr for CDF and 1E-07/yr for LERF.

Step 12-A3: Total Change Below 1E-06/yr CDF and 1E-07/yr LERF?

In Step 12-A3, the total CDF and LERF change from the individual STI change being assessed is compared to RG 1.174 limits for CDF and LERF changes – taken as CDF increase < 1E-06/yr and LERF increase < 1E-07/yr, for this method. If the above RG 1.174 limits are met, then proceed to Step 12-A4 to evaluate the cumulative impact of all STI changes. If the RG 1.174 limits for CDF and LERF changes are not met, proceed to Step 13 to consider a revised surveillance test interval for re-evaluation in Step 12 or to Step 4 to end the process.

Step 12-A4: Cumulative Change Below 1E-05/yr CDF and 1E-06/yr LERF?

In Step 12-A4, the cumulative CDF and LERF change from all of the individual STI changes are compared to the RG 1.174 limits for CDF and LERF changes. This means that the integrated impact of any previously approved changes using this process must be factored into the cumulative change. That is, the cumulative change shall be calculated by including revised failure probabilities due to all STI adjustments[3] approved using the SFCP (not just the sum of the individual assessments). Additionally, the total CDF must be reasonably shown to be less than 1E-04/yr when using the 1E-05/yr ΔCDF criterion and the total LERF must be reasonably shown to be less than 1E-05/yr when using the 1E-06/yr ΔLERF criterion. If the RG 1.174 limits are met (for both internal and external events at power as well as during shutdown), then proceed to Step 14 to perform sensitivity studies. If the RG 1.174 limits for CDF and LERF changes are not met, proceed to Step 13 to consider a revised surveillance test interval or to Step 4 to end the process.

Step 13: Revise STI Values

Step 13 is entered when it is determined that the Surveillance Frequency revisions do not meet the RG 1.174 acceptance criterion in Steps 12-A3 or 12-A4, are not supported by sensitivity study results (Step 14), or are not accepted by the IDP (Step 16 or Step 20). The surveillance frequencies are adjusted accordingly and re-evaluated in Step 12.

[3] See Step19 regarding the impact of PRA update on this process.

Step 14: Perform Sensitivity Studies

Carry out risk sensitivity studies by changing the unavailability terms for PRA basic events that correspond to SSCs being evaluated. As stated in Section 8 of NEI 00-04 (Ref. 14), the basic events for both random and common cause failure events shall be increased for failure modes impacted by the changes. A factor of three is appropriate as a sensitivity value because it is representative of the change in reliability between a mean value and an upper bound (95th percentile) for typical equipment reliability distributions. For example, for a lognormal distribution the ratio of the 95th percentile to the mean value would be approximately 2.4 for an error factor of 3 and 3.5 for an error factor of 10.

Additional sensitivity cases should also be explored for particular areas of uncertainty associated with any of the significant contributors to the CDF and LERF results or if there are open Gap Analysis items when compared to the ASME Standard Capability Category II that would impact the results of the assessment.

In practice, this means that the following steps shall be performed.

- At a minimum, re-perform all of the ΔCDF and ΔLERF determinations assuming that the standby failure rate of the basic event impacted by the STI change is 3 times larger than that used in the base case assessment. Simultaneously, adjust the corresponding standby failure contribution to the total common cause contribution by the same factor of three. Compare the revised CDF and LERF results to the RG 1.174 limits. Note that depending on the synergy of the contribution from all of the affected components due to the STI change, the net impact may be more than a factor of three on the calculated ΔCDF and ΔLERF evaluations.

- Determine if there is an impact from the STI change on the frequency of event initiators (those already included in the PRA and those screened out because of low frequency). For applications in this initiative, potentially significant initiators include valve failure that could lead to interfacing system loss-of-coolant accidents (LOCAs) or to other sequences that fail the containment isolation function. Include sensitivity case results that account for these items if it is determined that they are applicable for the STI change. Compare the revised CDF and LERF results to the RG 1.174 limits.

- Examine the significant contributors to the RG 1.200 delta assessment. From this evaluation, perform the following:

  – Ensure that there is no reliance on post-accident recovery of failed components affected by the STI (e.g. repair or ad-hoc manual actions, such as manually forcing stuck valves to open). However, credit may be taken for procedural implementation of alternative success strategies. If there is reliance on post-accident recovery of failed components affected by the STI, then re-perform the analysis with no credit taken for these repair or recovery actions. Compare the revised CDF and LERF results to the RG 1.174 limits.

– Ensure that there is not an undue reliance on key assumptions and causes of uncertainty, especially if there are open Gap Analysis items when compared to the ASME Standard Capability Category II that would impact the results of the assessment. If there is an undue reliance on uncertain model boundary conditions or key assumptions and parameters that would not be encompassed in the factor of three sensitivities identified above, then re-perform the analysis with revisions made to the basic event values associated with the identified key causes of uncertainty. Compare the revised CDF and LERF results to the RG 1.174 limits.

If the sensitivity evaluations support the STI changes (i.e., RG 1.174 limits are still met), then go to Step 15. Alternatively, if the sensitivity evaluations show that the changes in CDF and LERF as a result of changes in SSCs being evaluated are not within the acceptance guidelines of RG 1.174, then revised frequencies should be considered (go to Step 13). However, it is acceptable to proceed to Step 15 even if the results of the sensitivity studies are above the limits, provided the base case results are below the limits. At that point, qualitative considerations shall be developed to provide to the IDP to provide confidence that proceeding with the STI change is still acceptable even though sensitivity studies indicate that the change could exceed the RG 1.174 limits for the individual STI change.

Some examples of qualitative considerations that could be utilized to support the STI change even though it may not be supported by the sensitivity studies are listed below.

- There is plant-specific or industry experience available with other components of the same type that indicate that the failure probability will not be impacted by the STI change. In this case, the standby failure probability utilized for the assessment is not representative of real degradation impacts such that the implementation of the standby failure increase in the sensitivity studies is overly conservative.

- The performance of the test causes unavailability time that when factored into the analysis compared to the potential increase in the failure probability offsets the actual risk increase incurred.

- There are other considerations (e.g. there is an increased likelihood of plant trip associated with the performance of the test) that when factored into the analysis compared to the potential increase in the failure probability offsets the actual risk increase incurred.

Step 15: Summarize Qualitative and Quantitative Assessments and Establish Recommended Monitoring to be Addressed by IDP

The results from the following qualitative and quantitative assessments are documented and summarized for consideration by the IDP in Step 16:

- The results from the qualitative considerations developed in Step 7.
- The results from the evaluation of the total and cumulative effect on CDF and LERF generated in Step 12.
- The results from the sensitivity studies conducted in Step 14.
- The results from the qualitative and bounding analyses conducted in Steps 10a, 10b, and 10c for STI SSCs not modeled in the PRA.
- Recommended monitoring for SSCs.
- Recommended phased implementation, if applicable.

As an example, an evaluation form is provided in Appendix A as a guide for minimum documentation expectations.

Step 16: IDP Approval or Adjust STI

This step involves the use of an IDP that is charged with the task of reviewing the proposed STI for both qualitative considerations and the quantitative results.

The IDP is comprised of the site Maintenance Rule Expert Panel, a Surveillance Test Coordinator (STC), and a Subject Matter Expert (SME). The qualifications for IDP members who are Maintenance Rule Expert Panel members are the same as the Maintenance Rule Expert Panel qualifications. The STC is a specialist with experience in surveillance tests, and the SME is a specialist with experience in system or component reliability, e.g., a cognizant system manager or component engineer.

If the IDP approves the change, the changes are implemented and documented for future audits by NRC. If the IDP does not approve certain STI adjustments, then the STI value is not revised (in Step 13).

The IDP has additional responsibilities. These relate to making recommendations on the way the revised surveillance intervals are implemented (for instance, a phased implementation), reviewing the cumulative impact of all changes carried out over a period of time, monitoring the impact of changes on failure rates, and documenting the overall process.

An example IDP charter is provided in Appendix B.

Step 17: Document New STI and Implement the Changes

The STI changes approved by the IDP are documented appropriately and then implemented by revising plant procedures, affected documents, and training the personnel as needed. Essentially, the SFCP process stops here, however, long-term monitoring is still required per Step 18.

Step 18: Monitoring & Feedback

The purpose of performance monitoring in the SFCP process is twofold. First, performance monitoring should help confirm that no failure mechanisms that are related to the revised surveillance frequencies become important enough to alter the failure rates assumed in the justification of program changes. Second, performance monitoring should, to the extent practicable, ensure that adequate component capability (i.e., margin) exists relative to design-basis conditions so that component-operating characteristics, over time, do not result in reaching a point of insufficient margin before the next scheduled test. Regulatory Guide 1.175 (Ref. 5) provides guidance on performance monitoring when testing under design basis conditions is impracticable.

Two important aspects of performance monitoring are whether the test surveillance frequency is sufficient to provide meaningful data and whether the testing methods, procedures, and analysis are adequately developed to ensure that performance degradation is detected. Component failure rates should not be allowed to rise to unacceptable levels (e.g., significantly higher than the failure rates used to support the change) before detection and corrective action take place.

For acceptance guidelines, monitoring programs need be proposed that are capable of adequately tracking the performance of equipment that, when degraded, could alter the conclusions that were key to supporting the acceptance of revised surveillance frequencies. Monitoring programs should be structured such that SSCs are monitored commensurate with their safety significance. This allows for a reduced level of monitoring of components categorized as having low safety significance.

The performance monitoring process should have the following attributes:

- Enough tests are included to provide meaningful data.
- The test is devised such that incipient degradation can reasonably be expected to be detected.
- The licensee trends appropriate parameters as necessary, to provide reasonable assurance that the component will remain operable over the test interval.

The output of this step is sent to Step 19.

Step 19: Periodic Re-assessment

The SFCP contains provisions whereby component performance data is fed back periodically into the component test strategy determination (i.e., test interval and methods) process. This would include results of component or train level monitoring and results of Maintenance Rule (or §50.69 monitoring). The results of these periodic re-assessments are fed back to the IDP in Step 20 for evaluation.

Measures should also be in place to identify the need for more emergent program updates (e.g., following a major plant modification or following a significant equipment performance problem). Surveillance failures are evaluated under the Corrective Action Program. STI adjustments under the SFCP may be an appropriate corrective action for a surveillance failure. In addition, for a previously extended STI, if unsatisfactory performances of the surveillance occur, then an assessment shall be performed to determine if the time interval between performances of the surveillance is a factor in the cause of the unsatisfactory performance of the surveillance. The results of these emergent assessments are presented to the IDP in a timely manner in Step 20 for evaluation.

Part of the periodic re-assessment also includes interfacing the SFCP with updates of the PRA model. There are two options that exist to incorporate the revised STIs into the base PRA model. Option 1 is to use the original data assumptions that were utilized in performing the initial STI assessment. Option 2 is to utilize data collection and statistical analysis to show that the reliability of the components affected by the STI change has not been impacted, (or has improved), from the revised STI frequency value. It should, however, be realized that, depending on the STI frequency value, this latter option could take several years of data collection before statistically meaningful information is available.

The cumulative risk impact of all STIs changed using the SFCP is required to be compared to the RG 1.174 guidance for small changes whenever a new revised STI is proposed per the SFCP, per step 12-A4. When the PRA model is updated with the revised STI impact integrated into the base model per Option 1 or Option 2 above, individual changes to STIs that resulted in a change in CDF of less than 5E-08/yr, or change in LERF of less than 5E-09/yr, may be excluded from cumulative tracking following a PRA model update. However, the risk impact of all STI changes above these screening values shall be re-verified to remain within the RG 1.174 guidance for small changes when the base PRA model is updated. Adjustments to the revised STIs are required if the PRA model update results in exceeding the acceptance guidelines of the SFCP as described in Steps 12-A3 and 12-A4. Additionally, it is noted that if the SSC associated with the STI change is only evaluated by a qualitative analysis in Step 10a, or by a bounding analysis in Step 10b or Step 10c, then the STI change will not be modeled in the PRA update, and will therefore also be excluded from cumulative tracking. Implementation of interfacing the SFCP with PRA model updates is shown in Figure 3.

Step 20: IDP Reviews & Adjusts STI as Needed

The IDP is responsible for review of performance monitoring results (from Step 19) and attendant re-assessment of the program.

Step 20 is entered from Step 19 where the operating experience feedback following STI change implementation is periodically reviewed, or the results of an emergent assessment warrant review by the IDP, e.g., if it has been determined that the time interval between successive performances of a surveillance is a factor in the cause of unsatisfactory performances of the surveillance. In the case of the example, the IDP shall return the STI back to the previously acceptable STI.

Any changes identified by the IDP are routed to Step 13, or if no adjustments are required, monitoring is continued in accordance with Step 18. Results of periodic reassessment and any changes to an STI resulting from Step 18 (Monitoring and Feedback) and Step 19 (Periodic Re-assessment) are documented in accordance with the SFCP.

5.0 REFERENCES

1. 10 CFR 50.36, *"Technical specifications."*
2. 10 CFR 50.65, *"Requirements for monitoring the effectiveness of maintenance at nuclear power plants."*
3. 10 CFR 50, Appendix B, *"Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."*
4. NUMARC 93-01, "*Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,"* Rev. 3, July 2000 (NUMARC- currently Nuclear Energy Institute).
5. Regulatory Guide 1.175, "*An Approach for Plant-Specific Risk-Informed Decisionmaking: Inservice Testing,"* US Nuclear Regulatory Commission, *August 1998.*
6. Regulatory Guide 1.174, "*An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis,*" Revision 1, US Nuclear Regulatory Commission, November 2002.
7. Regulatory Guide 1.177, "*An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specification,"* US Nuclear Regulatory Commission, August 1998.
8. Regulatory Guide 1.200, *"An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,"* Revision 1, US Nuclear Regulatory Commission,January 2007.
9. 10 CFR 50, Appendix A, *"General Design Criteria for Nuclear Power Plants."*
10. NEI 99-04, *"Guidelines for Managing NRC Commitment Changes,"* Rev. 0, July 1999.
11. American Society of Mechanical Engineers, *"Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications,"* ASME RA-S-2002, April 5, 2002, and *"Addendum A to ASME RA-S-2002,"* ASME RA-Sa-2003, December 5, 2003, and *"Addendum B to ASME RA-S-2002,"* ASME RA-Sb-2005, December 30, 2005.
12. NEI 00-02, *"Probabilistic Risk Assessment (PRA) Peer Review Process Guidance,"* Rev.1, November 2006.
13. NUMARC 91-06, *"Guidelines for Industry Actions to Address Shutdown Management,"* December 1991.
14. NEI 00-04, *"10 CFR 50.69 SSC Categorization Guideline,"* Rev. 0, July 2005.
15. NUREG/CR-6141, "*Handbook of Methods for Risk-Based Analyses of Technical Specifications*," December 1994.
16. NUREG/CR-5497, *"Common-Cause Failure Parameter Estimations,"* October 1998.

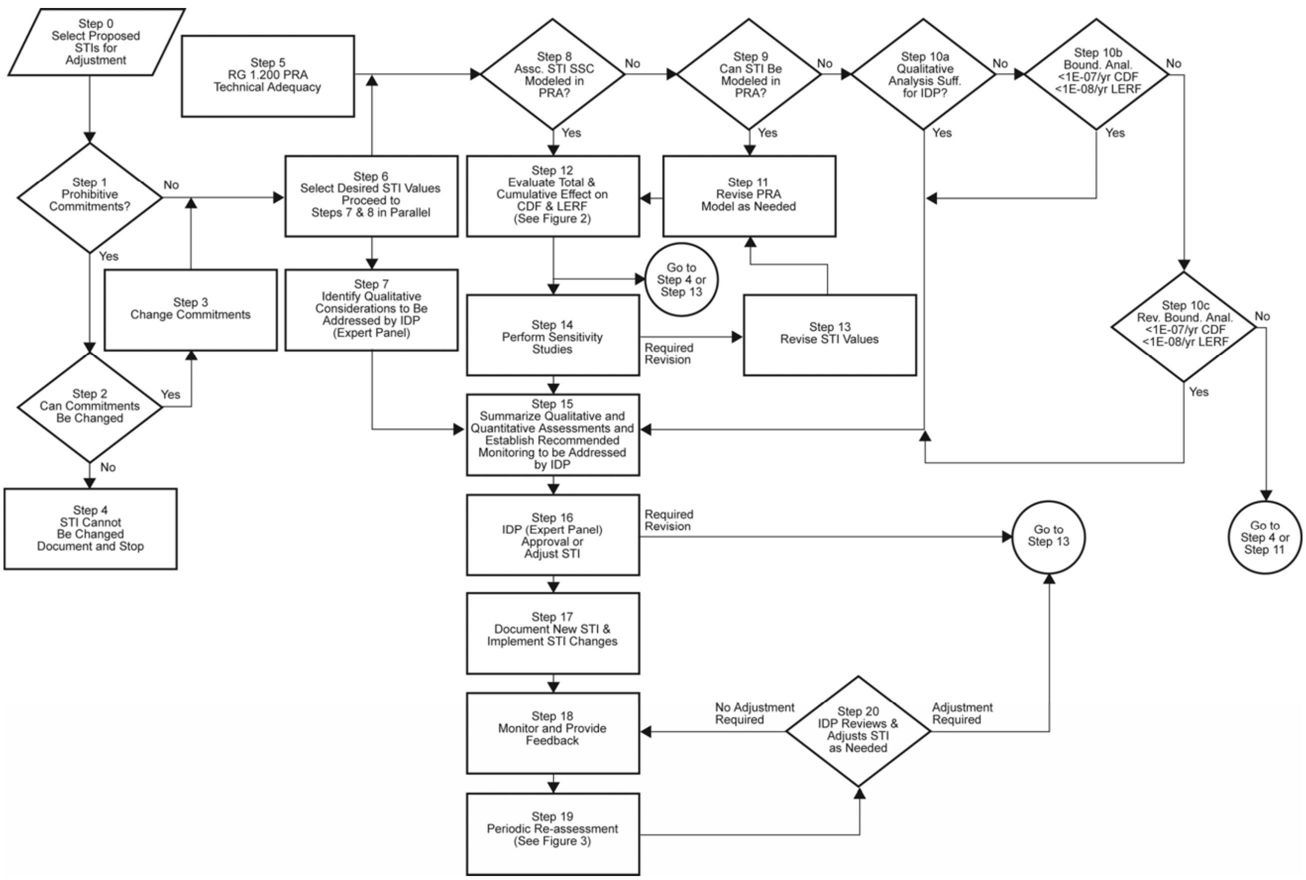


Figure 1. Surveillance Frequency Control Program Change Process

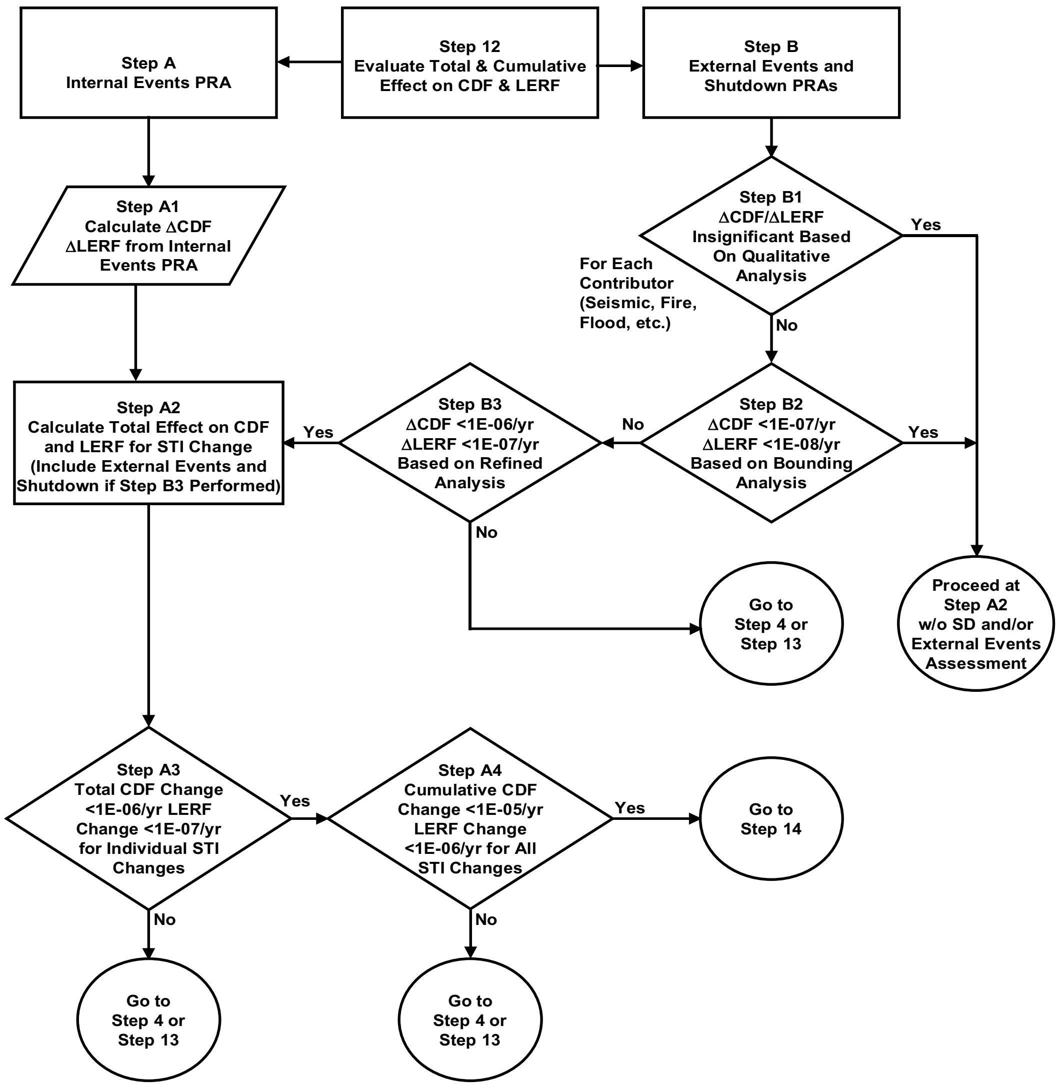
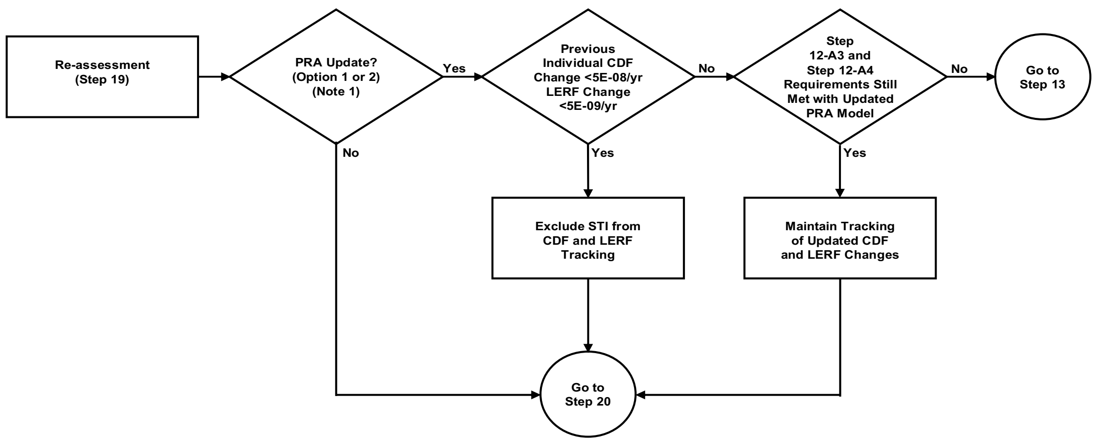


Figure 2. Evaluation of Total and Cumulative Effect on CDF and LERF



Note 1: If the SSC associated with the STI change is only evaluated by a qualitative analysis in Step 10a or by a bounding analysis in Step 10b or Step 10c, then the STI change will not be modeled in the PRA update.

Figure 3. Periodic Re-assessment Following a PRA Model Update

Appendix A
Surveillance Frequency Control Program

Sample Surveillance Test Frequency Evaluation Form

Surveillance Test Frequency Evaluation
RITSTF Initiative 5b Pilot (Ref. TSTF-425)

Station:_______________________________________Unit(s): ___________

Surveillance Test (ST) Number (s): _________________________________Revision Number:__________

Technical Specification Surveillance Requirement (SR) Number(s): ___________________

Technical Specification SR (Text): ____

Technical Specification SR Bases (and Intent):

____

____

____

Recommended ST Frequency Change: Adjust ST Frequency (Interval) from ____to_____
Adjust ST Strategy from ___to____

Station Benefit:

NOTES:
1: The terms Surveillance Test Interval (STI) and Surveillance Test Frequency are used interchangeably.

A.	**SYSTEM & MAINTENANCE RULE (MRule) INFORMATION**
1.	SYSTEM NUMBER: ____________________
2.	SYSTEM DESCRIPTION:
3.	CURRENT MRULE RISK SIGNIFICANCE (R-S) CLASSIFICATION (HSS OR LSS):
4.	CURRENT MRULE R-S BASIS:
5.	Current PRA RAW (System): ____________________ (MRule R-S threshold: $\geq$ 2.0)
6.	Current PRA RRW (System): ____________________ (MRule R-S threshold: $\geq$ 1.005)
7.	Current PRA Limiting Cutset (System): ____________________ (MRule R-S threshold: top 90%; Trigger value: __________)
B.	**QUALITATIVE ANALYSIS:**
1	COMMITMENT REVIEW (Is STI credited in any commitments?)
2	SURVEILLANCE TEST HISTORY OF THE COMPONENTS AND SYSTEM ASSOCIATED WITH THE STI ADJUSTMENT:
3	RELIABILITY REVIEW: PERFORMANCE (OPERATION & MAINTENANCE) HISTORY OF THE COMPONENTS AND SYSTEM ASSOCIATED WITH THE STI ADJUSTMENT: Maintenance Rule Train Actual Unreliability: __________, Maintenance Rule Unreliability Performance Criteria: _______ Additional component history review:

4	UNAVAILABILITY REVIEW: Maintenance Rule Train Actual Unavailability: _________ Maintenance Rule Unavailability Performance Criteria: ______

Surveillance Test Frequency Evaluation
RITSTF Initiative 5b Pilot (Ref. TSTF-425)

Procedure # TBD
Exhibit 1
Page 2 of 4

B.	**QUALITATIVE ANALYSIS:**
5	PAST INDUSTRY AND PLANT-SPECIFIC EXPERIENCE WITH THE FUNCTIONS AFFECTED BY THE PROPOSED CHANGES
6	VENDOR-SPECIFIED MAINTENANCE FREQUENCY
7	TEST INTERVALS SPECIFIED IN APPLICABLE INDUSTRY CODES AND STANDARDS
8	OTHER QUALITATIVE CONSIDERATIONS (include: comparison to Improved TS, alternate ST test list [retained], LCO review [optional], assumptions in plant licensing basis, degree ST provides conditioning exercise for operability, etc.)
9	**QUALITATIVE ANALYSIS – CONCLUSIONS**
10	PHASED IMPLEMENTATION REQUIREMENTS
11	PROPOSED SURROGATE MONITORING RECOMMENDATIONS: (Consider use of Existing Maintenance Rule monitoring)

12	Prepared by: ______________________________ (Subject Matter Expert) Date: ________ (System Manager or Component Specialist)

Surveillance Test Frequency Evaluation
RITSTF Initiative 5b Pilot (Ref. TSTF-425)

Procedure # TBD
Exhibit 1
Page 3 of 4

C.	**PRA ANALYSIS**
1	OVERVIEW OF PRA MODELING OF STI (include bounding risk analysis techniques if used, and PRA Quality Issues) Current PRA Model: ______________
2	FULL POWER INTERNAL EVENTS (FPIE) LEVEL 1 PRA MODEL IMPACTS (CDF Comparison against R.G 1.174 limits)
3	FPIE LEVEL 2 PRA MODEL IMPACTS (LERF Comparison against R.G 1.174 limits)
4	FIRE RISK IMPACTS (CDF & LERF Comparison against R.G 1.174 limits)
5	SEISMIC RISK IMPACTS (CDF & LERF Comparison against R.G 1.174 limits)
6	SHUTDOWN RISK IMPACTS (CDF & LERF Comparison against R.G 1.174 limits)
7	OTHER PRA ISSUES (ex. Impacts from Other External Events excluding seismic & Fire Risk Impacts, or changes in test strategy)
8	TOTAL EFFECT OF THIS STI EXTENSION ON INTERNAL, EXTERNAL & SHUTDOWN PRAs (CDF & LERF Comparison against R.G 1.174 limits)
9	CUMULATIVE EFFECT OF ALL RI-TS STI ADJUSTMENTS ON INTERNAL, EXTERNAL & SHUTDOWN PRAs. (CDF & LERF Comparison against R.G 1.174 limits)
10	IMPACT ON DEFENSE-IN-DEPTH PROTECTION
11	PRA ANALYSIS – CONCLUSIONS
12	Prepared by: ________________________________ Date ______________ (Risk Management [PRA] Engineer)

D.	**INTEGRATED DECISION-MAKING PANEL (IDP, a/k/a EXPERT PANEL) REVIEW**	MEETING DATE: ___________
1	Presenter(s): ____;	
2	Meeting Discussion Summary: (Review of Qualitative and Quantitative analyses, and Cumulative Impact)	
3	Meeting Results/Recommendations/Bases: (Consider: phased implementation, additional performance monitoring of failure rates) (include comment resolution)	
4	Approval/Disapproval: Check one of the following: ☐ STI Approved ☐ STI Approved with Comments ☐ STI Disapproved **IDP/Expert Panel Members** — Listing of IDP attendees: (signatures not required – see IDP meeting minutes) 1. Engineering Manager* ____________________ 2 Maintenance manager* ____________________ 3. Operations Manager* ____________________ 4. Risk Management (PRA) Engineer* ____________________ 5 Maintenance Rule Coordinator* ____________________ 6. Work Control / Work Management * ____________________ 7. Surveillance Test Coordinator ____________________ 8. System manager or Component Engineer ____________________ ***Also Maintenance Rule Expert Panel Member**	
5	**IDP COMMENT RESOLUTION** Prepared by: ______________________ Date: __________ (System Manager or Component Specialist) Prepared by: ______________________ Date: __________ (Risk Management Engineering)	
6	IDP/Expert Panel Coordinator Final Review/Closure: (All IDP comments resolved) ____________________ Date: ______________ (IDP Coordinator)	

Appendix B

Surveillance Frequency Control Program

Sample Plant IDP Charter

Sample Plant IDP Charter

Surveillance Frequency Control Program

Overview

The Surveillance Frequency Control Program (SFCP) pursues relocation of STIs from Technical Specifications to a licensee- controlled document such as the Technical Review Manual (TRM). The BWROG and NEI have developed a risk-informed methodology for extending the STI for the relocated tests. The plan is to submit a LAR for relocating the STIs using the methodology developed in NEI 04-10. Plant procedures to support STI implementation will be developed for each individual plant, including a revision to the plant Surveillance Test Program. Procedures are not required to be in effect until the LAR is submitted to the NRC. In the interim, the guideline will govern this process and IDP recommendations will specify the plan for each STI implementation. However, no STI change will be implemented until NRC approval is received.

IDP (Integrated Decisionmaking Panel[1]) Requirement

The STI methodology requires review by an IDP.
This charter provides an overview of IDP composition, roles and responsibilities per the guideline.

IDP Composition

IDP is comprised of the site MRule (Maintenance Rule) Expert Panel, Surveillance Test Coordinator (STC) and Subject Matter Expert (SME) who is a cognizant system manager or component engineer.

IDP Qualifications

- MRule Expert Panel Members: same as MRule Expert Panel qualification.
- Surveillance Test Coordinator (STC): a specialist with experience in surveillance tests.
- Subject Matter Expert (SME): a specialist with experience in system or component reliability.

[1] IDP is a term used in NEI 00-04, "10CFR50.69 SSC Categorization Guideline," Revision 0, July 2005, and also US NRC Reg. Guide 1.174, "An Approach for Using PRA and Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," July 1998.

IDP Roles & Responsibilities

1. Review the guideline Figures 1, 2 and 3 of the SFCP Process (NEI 04-10) to ensure that the flow chart pathway selected by the presenter(s) is correct for the specific STI.

2. Review the quantitative and qualitative PRA results (if applicable).

3. Review the qualitative considerations associated with STI adjustments. Qualitative considerations include, but are not limited to:

    a) ST and performance history of the components and system associated with the STI adjustment.
    b) Past industry and plant-specific experience with the functions affected by the proposed changes.
    c) Impact on defense-in-depth protection.
    d) Vendor-specified maintenance frequency.
    e) Test intervals specified in applicable industry codes and standards.
    f) Impact of a SSC in an adverse or harsh environment.
    g) Benefits of detection at an early stage of potential mechanisms and degradations that can lead to common cause failures.
    h) Assumptions in the plant licensing basis would not be invalidated when performing the surveillance at the bounding interval limit for the proposed STI changes.
    i) The degree to which the surveillance provides a conditioning exercise to maintain equipment operability.
    j) The existence of alternate testing of SSCs affected by the STI change.

4. Approval / Disapproval:

    - If the IDP approves the change, the changes will be implemented and documented for future audits by NRC.

    - If the IDP approves the change with comment(s), then the comment(s) will be resolved prior to changes being implemented and documented for future audits by NRC.

    - If the IDP disapproves an STI adjustment, then the STI value is left unchanged.

5. Implementation and monitoring:

- Consider phased implementation, by determining if the STI change should be implemented in a single step or in phases. Consider phased implementation for risk significant SSCs.

- Reviewing the cumulative impact of all STI changes carried out over a period of time. (This is also required by NRC risk-informed Reg. Guides 1.174 and 1.177).

- Monitoring the impact of changes on failure rates.

  a) The IDP can review a previously approved STI adjustment at a future date and reduce it if the performance trend shows increase in the failure rate of components or reduced reliability of the systems.

  b) Since it is not easy to detect changes in failure rate in a short time frame, the IDP should recommend surrogate parameters to be monitored in lieu of the failure rates. Typically, these will be performance indicators, for instance, pump discharge and discharge pressure flow in lieu of pump failure rate and valve opening and closing times in lieu of valve failure rate. Similar monitoring is already being done in response to the Maintenance Rule; it is therefore recommended that this task be added to the same team that carries it out for the Maintenance Rule. Component or train level monitoring would be expected for high risk SSCs. Component failure rates should not be allowed to rise to unacceptable levels (e.g., significantly higher than the failure rates used to support the change) before detection and corrective action take place. The intent of monitoring is to ensure that the component failure rates remain close to those used to support the STI change.

  c) Periodic Review of Performance Monitoring Results and Documentation of the Results from This Review: If the performance of the system, based on the performance indicator monitoring has a degrading trend, then this shall be brought to the attention of the IDP, which would then decide if the STI adjustment should be revised or revoked.

  d) Where there is a very low risk impact from the revised intervals, in general no additional monitoring should be proposed beyond the existing Maintenance Rule performance criteria.