MITIGATING SYSTEM PERFORMANCE INDEX

Purpose

The purpose of the Mitigating System Performance Index is to monitor the performance of selected systems based on their ability to perform risk-significant functions as defined herein. It is comprised of three elements - system unavailability, system unreliability and *system* component *performance limits*~~unreliability~~. The index is used to determine the cumulative significance of failures and unavailability over the monitored time period.

Indicator Definition

Mitigating System Performance Index (MSPI) is the sum of changes in a simplified core damage frequency evaluation resulting from differences in unavailability and unreliability relative to industry standard baseline values. The MSPI is supplemented with *system component performance limits.*~~a measure of degraded component performance that indicates when component performance in a given system is significantly lower than expected industry performance.~~

Unavailability is the ratio of the hours the train/system was unavailable to perform its risk-significant functions (as defined by PRA success criteria and mission times) due to planned and unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters. (Fault exposure hours are not included; unavailable hours are counted only from the time of discovery of a failed condition to the time ~~required to recover~~ the train's risk-significant functions *are recovered.*)

Unreliability is the probability that the train/system would not perform its risk-significant functions, as defined by PRA success criteria and mission times, when called upon during the previous 12 quarters.

Baseline values are the values for unavailability and unreliability against which current plant unavailability and unreliability are measured.

Component performance limit is a measure of degraded performance that indicates when the performance of a monitored component in an MSPI system is significantly lower than expected industry performance.

The MSPI is calculated separately for each of the following five systems for each reactor type.

BWRs

- emergency AC power system
- high pressure injection system (high pressure coolant injection, high pressure core spray, or feedwater coolant injection)
- reactor core isolation cooling(or *isolation condenser*~~equivalent~~)

- residual heat removal system (or the equivalent function as described in the Additional Guidance for Specific Systems section *of Appendix F*)
- cooling water support system (includes risk significant direct cooling functions provided by service water and component cooling water or their cooling water equivalents for the above four monitored systems)

PWRs

- emergency AC power system
- high pressure safety injection system
- auxiliary feedwater system
- residual heat removal system (or the equivalent function as described in the Additional Guidance for Specific Systems section *of Appendix F*)
- cooling water support system (includes risk significant direct cooling functions provided by service water and component cooling water or their cooling water equivalents for the above four monitored systems)

<u>Data Reporting Elements</u>

The following data elements are reported for each system

- Unavailability Index (UAI) due to unavailability for each monitored system
- Unreliability Index (URI) due to unreliability for each monitored system
- Systems that have exceeded their component *performance*~~unreliability~~ limits

<u>Calculation</u>

The MSPI for each system is the sum of the UAI due to unavailability for the system plus URI due to unreliability for the system during the previous twelve quarters.

$$MSPI = UAI + URI$$

Component *performance*~~unreliability~~ limits for each system are calculated as a maximum number of allowed failures (*Fm*) from the plant specific number of system demands and run hours. Actual numbers of equipment failures (*Fa*) are compared to these limits. This part of the indicator only applies to the green-white threshold.

See Appendix F for the calculation methodology for UAI due to system unavailability, URI due to system unreliability and system *component performance*~~reliability~~ limits.

The decision rules for assigning a performance color to a system are:

$$\text{IF}[(\text{MSPI} \leq 1.0\text{e-}06) \text{ AND } (\text{Fa} \leq \text{Fm})] \text{ THEN performance is GREEN}$$

$$\text{IF}\{[(\text{MSPI} \leq 1.0\text{e-}06) \text{ AND } (\text{Fa} > \text{Fm})] \text{ OR } [(\text{MSPI} > 1.0\text{e-}06) \text{ AND } (\text{MSPI} \leq 1.0\text{e-}05)]\}$$
$$\text{THEN performance is WHITE}$$

$$\text{IF}[(\text{MSPI} > 1.0\text{e-}05) \text{ AND } (\text{MSPI} \leq 1.0\text{e-}04)] \text{ THEN performance is YELLOW}$$

$$\text{IF}(\text{MSPI} > 1.0\text{e-}04) \text{ THEN performance is RED}$$

Plant Specific PRA

The MSPI calculation uses coefficients that are developed from plant specific PRAs. The PRA used to develop these coefficients should reasonably reflect the as-built, as-operated configuration of each plant. Updates to the MSPI coefficients developed from the plant specific PRA will be made as soon as practical following an update to the plant specific PRA. The revised coefficients will be used in the MSPI calculation the quarter following the update. Thus, the PRA coefficients in use at the beginning of a quarter will remain in effect for the remainder of that quarter.

Specific requirements appropriate for this PRA application are defined in Appendix G. Any questions related to the interpretation of these requirements, the use of alternate methods to meet the requirements or the conformance of a plant specific PRA to these requirements will be arbitrated by an Industry/NRC expert panel. The decisions of this panel will be binding.

Definition of Terms

Risk Significant Functions: those at power functions, described in the Appendix F section "Additional Guidance for Specific Systems," that were determined to be risk-significant in accordance with NUMARC 93-01, or NRC approved equivalents (e.g., the STP exemption request). The risk significant system functions described in Appendix F, "Additional Guidance for Specific Systems" should be modeled in the plant's PRA/PSA. System and equipment performance requirements for performing the risk significant functions are determined from the PRA success criteria for the system.

Risk-Significant Mission Time: The mission time modeled in the PRA for satisfying the risk-significant function of reaching a stable plant condition where normal shutdown cooling is sufficient. Note that PRA models typically use a mission time of 24 hours. However, shorter intervals, as justified by analyses and modeled in the PRA, may be used.

Success criteria: The plant specific values of parameters the train/system is required to achieve to perform its risk-significant functions. Success criteria to be used are those documented in the plant specific PRA. Design Basis success criteria should be used in the case where the plant specific PRA has not documented alternative success criteria for use in the PRA.

Individual component capability must be evaluated against train/system level success criteria (e.g., a valve stroke time may exceed an ASME requirement, but if the valve still strokes in time to meet the PRA success criteria for the train/system, the component has not failed for the purposes of this indicator. This is because the risk-significant train/system function is still satisfied).

Clarifying Notes

Documentation

Each licensee will have the system boundaries, monitored components, and risk-significant functions and success criteria which differ from design basis readily available for NRC inspection on site. Design basis criteria do not need to be separately documented. Additionally, plant-specific information used in Appendix F should also be readily available for inspection. An ~~example of an~~ acceptable format, *listing the minimum required* ~~for the~~ information, is provided in Appendix G.

Monitored Systems

Systems have been generically selected for this indicator based on their importance in preventing reactor core damage. The systems include the principal systems needed for maintaining reactor coolant inventory following a loss of coolant accident, for decay heat removal following a reactor trip or loss of main feedwater, and for providing emergency AC power following a loss of plant off-site power. One risk-significant support function (cooling water support system) is also monitored. The cooling water support system monitors the risk significant cooling functions provided by service water and component cooling water, or their direct cooling water equivalents, for the four front-line monitored systems. No support systems are to be cascaded onto the monitored systems, e.g., HVAC room coolers, DC power, instrument air, etc.

Diverse Systems

Except as specifically stated in the indicator definition and reporting guidance, no credit is given for the achievement of a risk-significant function by an unmonitored system in determining unavailability or unreliability of the monitored systems.

Use of Plant-Specific PRA and SPAR Models

The MSPI is an approximation using information from a plant's ~~actual~~ PRA and is intended as an indicator of system performance. More accurate calculations using plant-specific PRAs or SPAR models cannot be used to question the outcome of the PIs computed in accordance with this guideline.

APPENDIX F

METHODOLOGIES FOR COMPUTING THE UNAVAILABILITY INDEX, THE UNRELIABILITY INDEX AND COMPONENT PERFORMANCE LIMITS

This appendix provides the details of three calculations: the System Unavailability Index, the System Unreliability Index, and component performance limits.

1. System Unavailability Index (UAI) Due to Train Unavailability

Unavailability is monitored at the train level for the purpose of calculating UAI. The process for calculation of the System Unavailability Index has three major steps:

- Identification of system trains
- Collection of plant data
- Calculation of UAI

The first of these steps is performed for the initial setup of the index calculation. The second step has some parts that are performed initially and then only performed again when a revision to the plant specific PRA is made or changes are made to the normal preventive maintenance practices. Other parts of the calculation are performed periodically to obtain the data elements reported to the NRC. This section provides the detailed guidance for the calculation of UAI.

1.1. Identification of System Trains

The identification of system trains is accomplished in two steps:

- Determine the system boundaries
- Identify the trains within the system

The use of simplified P&IDs can be used to document the results of this step and will also facilitate the completion of the directions in section 2.1.1 later in this document.

1.1.1. System Boundaries

The first step in the identification of system trains is to define the system boundaries. Include all components that are required to satisfy the risk-significant functions of the system. For fluid systems the boundary should extend from the water source (e.g., tanks, sumps, etc.) to the injection point (e.g., RCS, Steam Generators). For example, high-pressure injection may have both an injection mode with suction from the refueling water storage tank and a recirculation mode with suction from the containment sump. For Emergency AC systems, the system consists of all class 1E generators at the station.

Additional system specific guidance on system boundaries can be found in section 5 titled "Additional Guidance for Specific Systems" at the end of this appendix.

Some common conditions that may occur are discussed below.

Component Interface Boundaries

For water connections from systems that provide cooling water to a single monitored component, only the final connecting valve is included in the boundary. For example, for service water that provides cooling to support an AFW pump, only the final valve in the service water system that supplies the cooling water to the AFW system is included in the AFW system scope. This same valve is not included in the cooling water support system scope.

Water Sources and Inventory

Water tanks are not considered to be monitored components. As such, they do not contribute to URI. However, periods of insufficient water inventory contribute to UAI if they result in loss of the risk-significant train function for the required mission time. ~~Water inventory can include operator recovery actions for water make-up provided the actions can be taken in time to meet the mission times and are modeled in the PRA.~~ If additional water sources are required to satisfy train mission times, only the connecting active valve from the additional water source is considered as a monitored component for calculating UAI. If there are valves in the primary water source that must change state to permit use of the additional water source, these valves are considered monitored and should be included in UAI for the system.

Common Components

Some components in a system may be common to more than one system, in which case the unavailability of a common component is included in all affected systems. (However, see "Additional Guidance for Specific Systems" for exceptions; for example, the PWR High Pressure Safety Injection System.)

1.1.2. Identification of Trains within the System

Each monitored system shall then be divided into trains to facilitate the monitoring of unavailability.

A train consists of a group of components that together provide the risk significant functions of the system as explained in the "additional guidance for specific mitigating systems". Fulfilling the risk-significant function of the system may require one or more trains of a system to operate simultaneously. The number of trains in a system is generally determined as follows:

- for systems that provide cooling of fluids, the number of trains is determined by the number of parallel heat exchangers, or the number of parallel pumps, or the minimum number of parallel flow paths, whichever is fewer.
- for emergency AC power systems the number of trains is the number of class 1E emergency (diesel, gas turbine, or hydroelectric) generators at the station that are installed to power shutdown loads in the event of a loss of off-site power. (This does not include the diesel generator dedicated to the BWR HPCS system, which is included in the scope of the HPCS system.)

Some components or flow paths may be included in the scope of more than one train. For example, one set of flow regulating valves and isolation valves in a three-pump, two-steam generator system are included in the motor-driven pump train with which they are electrically associated, but they are also included (along with the redundant set of valves) in the turbine-driven pump train. In these instances, the effects of unavailability of the valves should be reported in all affected trains. Similarly, when two trains provide flow to a common header, the effect of isolation or flow regulating valve failures in paths connected to the header should be considered in both trains.

Additional system specific guidance on train definition can be found in section 5 titled "Additional Guidance for Specific Systems" at the end of this appendix.

Additional guidance is provided below for the following specific circumstances that are commonly encountered:

- Cooling Water Support System Trains
- Swing Trains and Components Shared Between Units
- Maintenance Trains and Installed Spares

<u>Cooling Water Support Systems and Trains</u>

The cooling water function is typically accomplished by multiple systems, such as service water and component cooling water. A separate value for UAI will be calculated for each of the systems in this indicator and then they will be added together to calculate an overall UAI value.

In addition, cooling water systems are frequently not configured in discrete trains. In this case, the system should be divided into logical segments and each segment treated as a train. This approach is also valid for other fluid systems that are not configured in obvious trains. The way these functions are modeled in the plant-specific PRA will determine a logical approach for train determination. For example, if the PRA modeled separate pump and line segments (such as suction and discharge headers), then the number of pumps and line segments would be the number of trains.

<u>Unit Swing trains and components shared between units</u>

Swing trains/components are trains/components that can be aligned to any unit. To be credited as such, their swing capability must be modeled in the PRA to provide an appropriate Fussell-Vesely value.

<u>Maintenance Trains and Installed Spares</u>

Some power plants have systems with extra trains to allow preventive maintenance to be carried out with the unit at power without impacting the risk-significant function of the system.[1] That is, one of the remaining trains may fail, but the system can still perform its risk significant function. To be a maintenance train, a train must not be needed to perform the system's risk significant function.

An "installed spare" is a component (or set of components) that is used as a replacement for other equipment to allow for the removal of equipment from service for preventive or corrective maintenance without impacting the risk-significant function of the system. To be an "installed spare," a component must not be needed for the system to perform the risk significant function.

Unavailability of the spare component/train is only counted in the index if the spare is substituted for a primary train/component. Unavailability is not monitored for a component/train when that component/train has been replaced by an installed spare or maintenance train.

1.2. Collection of Plant Data

Plant data for the UAI portion of the index includes:

- Actual train total unavailability data for the most recent 12 quarter period collected on a quarterly basis,
- Plant specific baseline planned unavailability, and
- Generic baseline unplanned unavailability.

Each of these data inputs to UAI will be discussed in the following sections.

1.2.1. Actual Train Unavailability

The Consolidated Data Entry (CDE) inputs for this parameter are Train Unavailable Hours and Critical Hours. The actual calculation of Train Unavailability is performed by CDE.

Train Unavailability: Train unavailability is the ratio of the hours the train was unavailable to perform its risk-significant functions due to planned or unplanned maintenance or test during the previous 12 quarters while critical to the number of critical hours during the previous 12 quarters.

Train unavailable hours: The hours the train was not able to perform its risk significant function due to maintenance, testing, equipment modification, electively removed from service, corrective maintenance, or the elapsed time between the discovery and the restoration to service of an equipment failure or human error that makes the train unavailable (such as a misalignment) while the reactor is critical. Fault exposure hours are not included; unavailable hours are counted only for the time required to recover the train's risk-significant functions. Unavailability must be by train; do not use average unavailability for each train because trains may have unequal risk weights.

Additional guidance on the following topics for counting train unavailable hours is provided below.

- Short Duration Unavailability
- Credit for Operator Recovery Actions to Restore the Risk-Significant Function

Short Duration Unavailability

Trains are generally considered to be available during periodic system or equipment realignments to swap components or flow paths as part of normal operations. Evolutions or surveillance tests that result in less than 15 minutes of unavailable hours per train at a time need not be counted as unavailable hours. Licensees should compile a list of surveillances or evolutions that meet this criterion and have it available for inspector review. In addition, equipment misalignment or mispositioning which is corrected in less than 15 minutes need not be counted as unavailable hours. The intent is to minimize unnecessary burden of data collection, documentation, and verification because these short durations have insignificant risk impact. If a licensee is required to take a component out of service for evaluation and corrective actions for greater than 15 minutes (for example, related to a Part 21 Notification), the unavailable hours must be included.

Credit for Operator Recovery Actions to Restore the Risk-Significant Functions

1. *During testing or operational alignment*:

Unavailability of a risk-significant function during testing or operational alignment need not be included if the test configuration is automatically overridden by a valid starting signal, or the function can be promptly restored either by an operator in the control room or by a designated operator[1] stationed locally for that purpose. Restoration actions must be contained in a written procedure[2], must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated local operator can be taken only if (s)he is positioned at the proper location throughout the duration of the test for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration actions that are virtually certain to be successful (i.e., probability nearly equal to 1) during accident conditions.

The individual performing the restoration function can be the person conducting the test and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Normal staffing for the test may satisfy the requirement for a dedicated operator, depending on work assignments. In all cases, the staffing must be considered in advance and an operator identified to perform the restoration actions independent of other control room actions that may be required.

Under stressful, chaotic conditions, otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads

[1] Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

[2] Including restoration steps in an approved test procedure.

and landing wires; or clearing tags). In addition, some manual operations of systems designed to operate automatically, such as manually controlling HPCI turbine to establish and control injection flow, are not virtually certain to be successful. These situations should be resolved on a case-by-case basis through the FAQ process.

2. *During Maintenance*

Unavailability of a risk-significant function during maintenance need not be included if the risk-significant function can be promptly restored either by an operator in the control room or by a designated operator[3] stationed locally for that purpose. Restoration actions must be contained in a written procedure[4], must be uncomplicated (*a single action or a few simple actions*), must be capable of being restored in time to satisfy PRA success criteria and must not require diagnosis or repair. Credit for a designated local operator can be taken only if (s)he is positioned at a proper location throughout the duration of the maintenance activity for the purpose of restoration of the train should a valid demand occur. The intent of this paragraph is to allow licensees to take credit for restoration of risk-significant functions that are virtually certain to be successful (i.e., probability nearly equal to 1).

The individual performing the restoration function can be the person performing the maintenance and must be in communication with the control room. Credit can also be taken for an operator in the main control room provided (s)he is in close proximity to restore the equipment when needed. Normal staffing for the maintenance activity may satisfy the requirement for a dedicated operator, depending on work assignments. In all cases, the staffing must be considered in advance and an operator identified to perform the restoration actions independent of other control room actions that may be required.

Under stressful chaotic conditions otherwise simple multiple actions may not be accomplished with the virtual certainty called for by the guidance (e.g., lifting test leads and landing wires, or clearing tags). These situations should be resolved on a case-by-case basis through the FAQ process.

3. *During degraded conditions*
No credit is allowed for operator actions during degraded conditions that render the train unavailable to perform its risk-significant functions.

1.2.2. Plant Specific Baseline Planned Unavailability

The baseline planned unavailability is based on actual plant-specific values for the period *2002*~~2003~~ through ~~2005~~*2004*. (Plant specific values of the most recent data are used so that the indicator accurately reflects deviation from expected planned maintenance.)

[3] Operator in this circumstance refers to any plant personnel qualified and designated to perform the restoration function.

[4] Including restoration steps in an approved test procedure.

These values are expected to remain fixed unless the plant maintenance philosophy is substantially changed with respect to on-line maintenance or preventive maintenance. In these cases, the planned unavailability baseline value can be adjusted. A comment should be placed in the comment field of the quarterly report to identify a substantial change in planned unavailability. The baseline value of planned unavailability may be changed at the discretion of the licensee except that they shall be changed when changes in maintenance practices result in greater than a 25% change in planned unavailability. Revised values will be used in the calculation the quarter following their update.

To determine the initial value of planned unavailability:

1) Record the total train unavailable hours reported under the Reactor Oversight Process for 2002~~3~~-2004~~5~~.
2) Subtract any fault exposure hours still included in the 2002~~3~~-200~~5~~4 period.
3) Subtract unplanned unavailable hours.
4) Add any on-line overhaul hours and any other planned unavailability excluded in accordance with NEI 99-02. [5]
5) Add any planned unavailable hours for functions monitored under MSPI which were not monitored under SSU in NEI 99-02.
6) Subtract any unavailable hours reported when the reactor was not critical.
7) Subtract hours cascaded onto monitored systems by support systems. (However, do not subtract any hours already subtracted in the above steps.)
8) Divide the hours derived from steps 1-7 above by the total critical hours during 2002~~3~~-2004~~5~~. This is the baseline planned unavailability.

Support cooling planned unavailability baseline data is based on plant specific maintenance rule unavailability for years 2002~~3~~-200~~5~~4. Maintenance Rule practices do not typically differentiate planned from unplanned unavailability. However, best efforts will be made to differentiate planned and unplanned unavailability during this time period.

1.2.3. Generic Baseline Unplanned Unavailability

The unplanned unavailability values are contained in Table 1 and remain fixed. They are based on ROP PI industry data from 1999 through 2001. (Most baseline data used in Pis come from the 1995-1997 time period. However, in this case, the 1999-2001 ROP data are preferable, because the ROP data breaks out systems separately. Some of the industry 1995-1997 INPO data combine systems, such as HPCI and RCIC, and do not include PWR RHR. It is important to note that the data for the two periods is very similar.)

[5] Note: The plant-specific PRA should model significant on-line overhaul hours.

Table 1. Historical Unplanned Unavailability Train Values
(Based on ROP Industry wide Data for 1999 through 2001)

SYSTEM	UNPLANNED UNAVAILABILITY/TRAIN
EAC	1.7 E-03
PWR HPSI	6.1 E-04
PWR AFW (TD)	9.1 E-04
PWR AFW (MD)	6.9 E-04
PWR AFW (DieselD)	7.6 E-04
PWR (except CE) RHR	4.2 E-04
CE RHR	1.1 E-03
BWR HPCI	3.3 E-03
BWR HPCS	5.4 E-04
BWR RCIC	2.9 E-03
BWR IC	Need a value for isolation condensers
BWR RHR	1.2 E-03
Support Cooling	Use plant specific Maintenance Rule data for *2002-2004*~~2003-2005~~

Unplanned unavailability baseline data for the support cooling systems should be developed from plant specific Maintenance Rule data from the period *2002-2004*~~2003-2005~~. Maintenance Rule practices do not typically differentiate planned from unplanned unavailability. However, best efforts will be made to differentiate planned and unplanned unavailability during this time period. NOTE: The sum of planned and unplanned unavailability cannot exceed the total unavailability.

1.3.Calculation of UAI

The specific formula for the calculation of UAI is provided in this section. Each term in the formula will be defined individually and specific guidance provided for the calculation of each term in the equation. Required inputs to the INPO Consolidated Data Entry (CDE) System will be identified.

Calculation of System UAI due to train unavailability is as follows:

$$UAI = \sum_{j=1}^{n} UAI_{tj} \qquad \text{Eq. 1}$$

where the summation is over the number of trains (n) and UAI_t is the unavailability index for a train.

Calculation of UAI_t for each train due to actual train unavailability is as follows:

$$UAIt = CDFp\left[\frac{FVUAp}{UAp}\right]_{max}(UAt - UABLt) \quad \text{Eq. 2}$$

where:

CDF_p is the plant-specific Core Damage Frequency,

FV_{UAp} is the train-specific Fussell-Vesely value for unavailability,

UA_P is the plant-specific PRA value of unavailability for the train,

UA_t is the actual unavailability of train t, defined as:

$$UAt = \frac{\text{Unavailable hours during the previous 12 quarters while critical}}{\text{Critical hours during the previous 12 quarters}}$$

and, determined in section 1.21

UA_{BLt} is the historical baseline unavailability value for the train (sum of planned unavailability determined in section 1.2.2 and unplanned unavailability in section1.2.3)

Calculation of the quantities in equation 2 are discussed in the following sections.

1.3.1. Calculation of Core Damage Frequency (CDFp)

The Core Damage Frequency is a CDE input value. The required value is the <u>internal events, average maintenance,</u> at power value. Internal flooding and fire are not included in this calculated value. In general, all inputs to this indicator from the PRA are calculated from the internal events model only.

1.3.2. Calculation of [FV/UA]max for each train

FV and UA are separate CDE input values. Equation 2 includes a term that is the ratio of a Fussell-Vesely importance value divided by the related unavailability. This ratio is calculated for each train in the system and both the FV and UA are CDE inputs. (It may be recognized that the quantity [FV/UA] multiplied by the CDF is the Birnbaum importance measure, which is used in section 2.3.3.)

Calculation of these quantities is generally complex, but in the specific application used here, can be greatly simplified.

The simplifying feature of this application is that only those components (or the associated basic events) that can make a train unavailable are considered in the performance index. Components within a train that can each make the train unavailable are logically equivalent and the ratio FV/UA is a constant value for any basic event in that train. It can also be shown that for a given component or train represented by multiple basic events, the ratio of the two values for the component or train is equal to the ratio of values for any basic event within the train. Or:

$$\frac{FV_{be}}{UA_{be}} = \frac{FVUAp}{UAp} = \text{Constant}$$

Thus, the process for determining the value of this ratio for any train is to identify a basic event that fails the train, determine the unavailability for the event, determine the associated FV value for the event and then calculate the ratio. Use the basic event in the train with the largest failure probability (hence the maximum notation on the bracket) to minimize the effects of truncation on the calculation.

Some systems have multiple modes of operation, such as PWR HPSI systems that operate in injection as well as recirculation modes. In these systems all monitored components are not logically equivalent; unavailability of the pump fails all operating modes while unavailability of the sump suction valves only fails the recirculation mode. In cases such as these, if unavailability events exist separately for the components within a train, the appropriate ratio to use is the maximum.

Note: If the basic event Be is truncated in quantification and has no FV to ratio, do not include the train in the MSPI scope. [What level of truncation is appropriate?]

2. System Unreliability Index (URI) Due to Component Unreliability

Calculation of the URI is performed in three major steps:

- Identification of the monitored components for each system
- Collection of plant data
- Calculation of the URI

Only the most risk significant components in each system are monitored to minimize the burden for each utility. It is expected that most, if not all the components identified for monitoring are already being monitored for failure reporting to INPO and are also monitored in accordance with the maintenance rule.

2.1. Identify Monitored Components

Monitored Component: A component whose failure to change state or remain running renders the train incapable of performing its risk-significant functions. In addition, all pumps and diesels in the monitored systems are included as monitored components.

The identification of monitored components involves the use of the system boundaries and success criteria, identification of the components to be monitored within the system boundary and the scope definition for each component.

2.1.1. System Boundaries and Success Criteria

The system boundaries developed in section 1.1.1 should be used to complete the steps in the following section.

For each system, the at power risk significant functions described in the Appendix F section "Additional Guidance for Specific Systems," that were determined to be risk-significant in accordance with NUMARC 93-01, or NRC approved equivalents (e.g., the STP exemption request) shall be identified. Success criteria shall then be identified for these functions.

If the licensee has chosen to use success criteria documented in the plant specific PRA, examples of plant specific performance factors that may be used to identify the required capability of the train/system to meet the risk-significant functions are provided below.

- Actuation
  - Time
  - Auto/manual
  - Multiple or sequential
- Success requirements
  - Numbers of components or trains
  - Flows
  - Pressures
  - Heat exchange rates
  - Temperatures
  - Tank water level
- Other mission requirements
  - Run time
  - State/configuration changes during mission
- Accident environment from internal events
  - Pressure, temperature, humidity
- Operational factors
  - Procedures
  - Human actions
  - Training
  - Available externalities (e.g., power supplies, special equipment, etc.)

If the licensee has chosen to use design basis success criteria, it is not required to separately document them other than to indicate that is what was used.

If success criteria for a system vary by function or initiator, the most restrictive set will be used for the MSPI.

2.1.2. Selection of Components

For unreliability, use the following process for determining those components that should be monitored. These steps should be applied in the order listed.

1) INCLUDE all pumps and diesels.

2) Identify all AOV's and MOV's that change state to achieve the risk significant functions for the system as potential monitored components. Check valves, solenoid valves and manual valves are not included in the index.

   a. INCLUDE those valves from the list of valves from step 2 whose failure alone can fail a train. The success criteria used to identify these valves are those identified in the previous section. (See Figure F-5)

   b. INCLUDE redundant valves from the list of valves from step 2 within a multi-train system, whether in series or parallel, where the failure of both valves would prevent all trains in the system from performing a risk-significant function. The success criteria used to identify these valves are those identified in the previous section.(See Figure F-5)

c. EXCLUDE those valves from steps a) and b) above whose Birnbaum importance, (See section 2.3.3) as calculated in this appendix, is less than 1.0e-06. This rule is applied at the discretion of the individual plant. A balance should be considered in applying this rule between the goal to minimize the number of components monitored and having a large enough set of components to have an adequate data pool.

3) INCLUDE components that cross tie monitored systems between units (i.e. Electrical Breakers and Valves) if they are modeled in the PRA.

2.1.3. Definition of Component Boundaries

Table 2 defines the boundaries of components, and Figures F-1, F-2, F-3 and F-4 provide examples of typical component boundaries as described in Table 2.

Table 2. Component Boundary Definition

Component	Component boundary
Diesel Generators	The diesel generator boundary includes the generator body, generator actuator, lubrication system (local), fuel system (local), cooling components (local), startup air system receiver, exhaust and combustion air system, dedicated diesel battery (which is not part of the normal DC distribution system), individual diesel generator control system, circuit breaker for supply to safeguard buses and their associated local control circuit (coil, auxiliary contacts, wiring and control circuit contacts, and breaker closure interlocks) .
Motor-Driven Pumps	The pump boundary includes the pump body, motor/actuator, lubrication system cooling components of the pump seals, the voltage supply breaker, and its associated local control circuit (coil, auxiliary contacts, wiring and control circuit contacts).
Turbine-Driven Pumps	The turbine-driven pump boundary includes the pump body, turbine/actuator, lubrication system (including pump), extractions, turbo-pump seal, cooling components, and local turbine control system including the control valve (speed).
Motor-Operated Valves	The valve boundary includes the valve body, motor/actuator, the voltage supply breaker (both motive and control power) and its associated local open/close circuit (open/close switches, auxiliary and switch contacts, and wiring and switch energization contacts).
Air-Operated Valves	The valve boundary includes the valve body, the air operator, associated solenoid-operated valve, the power supply breaker or fuse for the solenoid valve, and its associated control circuit (open/close switches and local auxiliary and switch contacts).

For control and motive power, only the last relay, breaker or contactor necessary to power or control the component is included in the monitored component boundary. For example, if an ESFAS signal actuates a MOV, only the relay that receives the ESFAS signal in the control circuitry for the MOV is in the MOV boundary. No other portions of the ESFAS are included.

Each plant will determine their monitored components and support components and have them available for NRC inspection.

2.2. Collection of Plant Data

Plant data for the URI includes:

- Demands and run hours
- Failures

2.2.1. Demands and Run Hours

Start demand: Any demand for the component to successfully start to perform its risk-significant functions, actual or test. (Exclude post maintenance tests, unless in case of a failure the cause of failure was independent of the maintenance performed.) The number of demands is:

- the number of actual ESF demands plus
- the number of estimated test demands plus
- the number of estimated operational/alignment demands.

The number of estimated demands can be derived based on the number of times a procedure or maintenance activity is performed, or based on historical data over a year or more averaged to provide a quarterly average. It is also permissible to use the actual number of test and operational demands.

An update to the estimated demands is required if a change to the basis for the estimated demands results in a >25% change in the estimate. The new estimate will be used in the calculation the quarter following the input of the updated estimates into CDE. Some monitored valves will include a throttle function as well as open and close functions. ~~It is not required to include every throttle movement of a valve as a counted demand~~*One should not include every throttle movement of a valve as a counted demand.* Only the initial movement of the valve should be counted as a demand.

Some components such as valves make need to be in different states at different times to fulfill the risk significant function of the monitored system. In this case each change of state is a demand. An example would be a minimum flow valve that needs to open on the pump start (one demand) then close (second demand) to prevent a diversion path or a valve needs to open(one demand) for the initial water supply then close (second demand) while another water supply valve opens.

Post maintenance tests: Tests performed following maintenance but prior to declaring the train/component operable, consistent with Maintenance Rule implementation.

Run demand: Any demand for the component, given that it has successfully started and run for 1 hour, to run/operate for its mission time to perform its risk-significant functions.

(Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Run Hours: The number of run hours is:

- the number of actual ESF run hours plus
- the number of estimated test run hours plus
- the number of estimated operational/alignment run hours.

The number of estimated run hours can be derived based on the number of times a procedure or maintenance activity is performed, or based on historical data over a year or more averaged to provide a quarterly average. It is also permissible to use the actual number of test and operational run hours. Run hours include the first hour of operation of a component. An update to the estimated run hours is required if a change to the basis for the estimated hours results in a >25% change in the estimate. *The new estimate will be used in the calculation the quarter following the input of the updated estimates into CDE.*

2.2.2. Failures

EDG failure to start: A failure to start includes those failures up to the point the EDG has achieved rated speed and voltage. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

EDG failure to load/run: Given that it has successfully started, a failure of the EDG output breaker to close, to successfully load sequence and to run/operate for one hour to perform its risk-significant functions. This failure mode is treated as a demand failure for calculation purposes. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

EDG failure to run: Given that it has successfully started and loaded and run for an hour, a failure of an EDG to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Pump failure on demand: A failure to start and run for at least one hour is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Pump failure to run: Given that it has successfully started and run for an hour, a failure of a pump to run/operate. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Valve failure on demand: A failure to transfer to the required risk significant ~~position~~*state* (open, close, or throttle to the desired position as applicable) is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

Breaker failure on demand: A failure to transfer to the required risk significant ~~position~~*state* (open or close as applicable) is counted as failure on demand. (Exclude post maintenance tests, unless the cause of failure was independent of the maintenance performed.)

<u>Treatment of Demand and Run Failures</u>

Failures of monitored components on demand or failures to run, either actual or test are included in unreliability. Failures on demand or failures to run while not critical are included unless an evaluation determines the failure would not have affected the ability of the component to perform its risk-significant at power function. In no case can a postulated action to recover a failure be used as a justification to exclude a failure from the count.

<u>Treatment of Degraded Conditions Capable of Being Discovered By Normal Surveillance Tests</u>

Normal surveillance tests are those tests that are performed at a frequency of a refueling cycle or more frequently.

Degraded conditions, even if no actual demand or test existed, that render a monitored component incapable of performing its risk-significant functions are included in unreliability as a demand and a failure. The appropriate failure mode must be accounted for. For example, for valves, a demand and a demand failure would be assumed and included in URI. For pumps and diesels, if the degraded condition would have prevented a successful start, a demand and a failure is included in URI, but there would be no run time hours or run failures. If it was determined that the pump/diesel would start and load run, but would fail sometime during the 24 hour run test or its surveillance test equivalent, the evaluated failure time would be included in run hours and a run failure would be assumed. A start demand and start failure would not be included. If a running component is secured from operation due to observed degraded performance, but prior to failure, then a run failure shall be counted unless evaluation of the condition shows that the component would have continued to operate for the risk-significant mission time starting from the time the component was secured. Unavailable hours are included for the time required to recover the risk-significant function(s) and only while critical.

Degraded conditions, or actual unavailability due to mispositioning of non-monitored components that render a train incapable of performing its risk-significant functions are only included in unavailability for the time required to recover the risk-significant function(s) and only while critical.

Loss of risk significant function(s) is assumed to have occurred if the established success criteria have not been met. If subsequent analysis identifies additional margin for the success criterion, future impacts on URI or UAI for degraded conditions may be determined based on the new criterion. However, *the current quarter's* URI and UAI must be based on the success criteria of record at the time the degraded condition is discovered. *If subsequently, new success criteria are to be used, they must be included in the PRA and the MSPI basis document.*

If the degraded condition is not addressed by any of the pre-defined success criteria, an engineering evaluation to determine the impact of the degraded condition on the risk-significant function(s) should be completed and documented. The use of component failure analysis, circuit analysis, or event investigations is acceptable. Engineering judgment may be used in conjunction with analytical techniques to determine the impact of the degraded condition on the risk-significant function. The engineering evaluation should be completed as soon as practicable. If it cannot be completed in time to support submission of the PI report for the current quarter, the comment field shall note that an evaluation is pending. The evaluation must be completed in time to accurately account for unavailability/unreliability in the next quarterly report. Exceptions to this guidance are expected to be rare and will be treated on a case-by-case basis. Licensees should identify these situations to the resident inspector.

Treatment of Degraded Conditions Not Capable of Being Discovered by Normal Surveillance Tests

These failures or conditions are usually of longer exposure time. Since these failure modes have not been tested on a regular basis, it is inappropriate to include them in the performance index statistics. These failures or conditions are subject to evaluation through the inspection process. Examples of this type are failures due to pressure locking/thermal binding of isolation valves, blockages in lines not regularly tested, unforeseen sequences not incorporated into the surveillance test, or inadequate component sizing/settings under accident conditions (not under normal test conditions). While not included in the calculation of the index, they should be reported in the comment field of the PI data submittal.

Failures of Non-Monitored Components

Failures of SSC's that are not included in the performance index will not be counted as a failure or a demand. Failures of SSC's that cause an SSC within the scope of the performance index to fail will not be counted as a failure or demand. An example could be a manual suction isolation valve left closed which causes a pump to fail. This would not be counted as a failure of the pump. Any mispositioning of the valve that caused the train to be unavailable would be counted as unavailability from the time of discovery. The significance of the mispositioned valve prior to discovery would be addressed through the inspection process.

2.3. Calculation of URI

Unreliability is monitored at the component level and calculated at the system level. Calculation of system URI due to changes in component unreliability is as follows:

$$URI = CDF_P \sum_{j=1}^{m} \left[\frac{FV_{URcj}}{UR_{pcj}}\right]_{max} (UR_{Bcj} - UR_{BLcj}) \qquad \text{Eq. 3}$$

Where the summation is over the number of monitored components (m) in the system, and:

CDF_p is the plant-specific Core Damage Frequency,

FV_{URc} is the component-specific Fussell-Vesely value for unreliability,

UR_{Pc} is the plant-specific PRA value of component unreliability,

UR_{Bc} is the Bayesian corrected component unreliability for the previous 12 quarters, and

UR_{BLc} is the historical industry baseline calculated from unreliability mean values for each monitored component in the system. The calculation is performed in a manner similar to equation 6 in section 2.3.4 below using the industry average values in Table 4.

The following sections will discuss the calculation of each of the terms in equation 3.

2.3.1. Calculation of Core Damage Frequency (CDFp)

The Core Damage Frequency is a CDE input value. The required value is the internal events average maintenance at power value. Internal flooding and fire are not included in this calculated value. In general, all inputs to this indicator from the PRA are calculated from the internal events model only.

2.3.2. Calculation of [FV/UR]max

The FV, UR and common cause adjustment values developed in this section are separate CDE input values.

Equation 3 includes a term that is the ratio of a Fussell-Vesely importance value divided by the related unreliability. The calculation of this ratio is performed in a similar manner to the ratio calculated for UAI, except that the ratio is calculated for each monitored component. Two additional factors need to be accounted for in the unreliability ratios that were not needed in the unavailability ratios, the contribution to the ratio from common cause failure events and the possible contribution from cooling water initiating events. The discussion will start with the calculation of the initial ratio and then proceed with options for adjusting this value to account for the additional two factors.

It can be shown that for a given component represented by multiple basic events, the ratio of the two values for the component is equal to the ratio of values for any basic event representing the component. Or:

$$\frac{FVbe}{URbe} = \frac{FVURc}{URPc} = \text{Constant}$$

Note that the constant value may be different for the unreliability ratio and the unavailability ratio because the two types of events are frequently not logically equivalent. For example recovery actions may be modeled in the PRA for one but not the other.

Thus, the process for determining the initial value of this ratio for any component is to identify a basic event that fails the component (excluding common cause events), determine the failure probability for the event, determine the associated FV value for the event and then calculate the ratio, $[FV/UR]_{ind}$, where the subscript refers to independent failures. Use the basic event for the component and its associated FV value that results in the largest *[FV/UR]* ratio. This will typically be the event with the largest failure probability to minimize the effects of truncation on the calculation.

It is typical, given the component scope definitions in Table 2, that there will be several plant components modeled separately in the plant PRA that make up the MSPI component definition. For example, it is common that an MOV, the actuation relay for the MOV and the power supply breaker for the MOV are separate components in the plant PRA. Ensure that the basic events related to all of these individual components are considered when choosing the appropriate *[FV/UR]* ratio.

If the basic event Be is truncated in quantification, do not include the component in the scope of the MSPI. [What level of truncation is appropriate?]

Cooling Water and Service Water System $[FV/UR]_{ind}$ Values

Component Cooling Water Systems (CCW) and Service Water Systems (SWS) at some nuclear stations contribute to risk in two ways. First, the systems provide cooling to equipment used for the mitigation of events and second, the failures in the systems may also result in the initiation of an event. The contribution to risk from failures to provide cooling to other plant equipment is modeled directly through dependencies in the PRA model. However, the contribution due to event initiation is treated in three general ways in current PRAs:

1) The use of linked initiating event fault trees for these systems
2) Fault tree solutions are generated for these systems external to the PRA and the calculated value is used in the PRA as a point estimate
3) A point estimate value is generated for the initiator using industry and plant specific event data and used in the PRA.

If a PRA uses the first modeling option, then the FV values calculated will reflect the total contribution to risk for a component in the system, **as long the same basic event is used in the initiator and mitigation fault trees.** If different basic events are used, the FV values for the initiator tree basic event and the mitigation tree basic event should be added.

If a linked initiating event fault tree is the modeling approach taken, then no additional corrections to the FV values is required. This section will outline a method to be used to if linked initiating event fault trees are not used.

The corrected $[FV/UR]_{ind}$ for a component C is calculated from the expression:

$$[FV/UR]ind = [(FVc + FVie * FVsc)/UR]$$

Where:

FVc is the Fussell-Vesely for CDF for component C as calculated from the PRA Model. This does not include any contribution from initiating events.

$FVie$ is the Fussell-Vesely contribution for the initiating event in question (e.g. loss of service water).

$FVsc$ is the Fussell-Vesely **within the system fault tree only** for component C (i.e. the ratio of the sum of the cut sets in the fault tree solution in which that component appears to the overall system failure probability).

$[FV/UR]_{ind}$ is a CDE input value.

Including the Effect of Common Cause in $[FV/UR]_{max}$

Changes in the independent failure probability of an SSC imply a proportional change in the common cause failure probability, even though no actual common cause failures have occurred. The impact of this effect on URI is considered by including a multiplicative adjustment to the $[FV/UR]_{ind}$ ratio developed in the section above. This multiplicative factor is a CDE input value.

Two methods are provided for including this effect, a simple generic approach that uses bounding generic adjustment and a more accurate plant specific method that uses values derived from the plant specific PRA.

<u>Generic Adjustment Values</u>

Generic values have been developed for monitored components that are subject to common cause failure. The correction factor is used as a multiplier on the [FV/UR] ratio for each component in the common cause group. This method may be used for simplicity and is recommended for components that are less significant contributors to the URI (e.g. [FV/UR] is small). The multipliers are provided in the table below. Single train systems are not included.

Table 3. Generic CCF Adjustment Values

System	Component	Generic CCF Adjustment Values				
		1.25	1.50	2.00	3.00	5.00
EAC	EDG	2 EDGs (1/2) or 3 EDGs (2/3)	4 EDGs(1/4) with other diverse sources of power	3 EDGs(1/3)		4 EDGs(1/4) and no diverse sources of power
HPI	MDP Running		With SI and CVC		With only CVC	
	MDP Standby		With SI and CVC		With only SI	
HRS	MDP Standby	2 MDP (1/2)			3 MDP (1/3)	
	TDP	2 TDP and 1 MDP			3 TDP and no MDP	
RHR	MDP Standby		ALL			
SWS	MDP Running				ALL	
	MDP Standby		ALL			
	DDP	ALL				
CCW	MDP Running		ALL			
	MDP Standby			ALL		
ALL	MOV			ALL		

System	Component	Generic CCF Adjustment Values				
		1.25	1.50	2.00	3.00	5.00
ALL	AOV		ALL			
Note: Success criteria noted in parenthesis						

NOTE THIS TABLE WILL BE DEVELOPED FOR ALL PLANTS

The Multiplier in the table above is used to adjust the FV value selected for use in the preceding section. For example, at a plant with three one hundred percent capacity EDG's, the FV selected in the preceding section would be multiplied by 2.00.

Plant Specific Common Cause Adjustment

The general form of a plant specific common cause adjustment factor is given by the equation:

$$A = \frac{\left[\left(\sum_{i=1}^{n} FVi\right) + FVcc\right]}{\sum_{i=1}^{n} FVi}. \qquad \text{Eq. 4}$$

Where:

n = is the number of components in a common cause group,

FV_i = the FV for independent failure of component i,

and

FV_{cc} = the FV for the common cause failure of components in the group.

In the expression above, the FV_i are the values for the specific failure mode for the component group that was chosen because it resulted in the maximum *[FV/UR]* ratio. The FV_{cc} is the FV that corresponds to all combinations of common cause events for that group of components for the same specific failure mode. Note that the FV_{cc} may be a sum of individual FV_{cc} values that represent different combinations of component failures in a common cause group.

For example consider again a plant with three one hundred percent capacity emergency diesel generators. In this example, three failure modes for the EDG are modeled in the PRA, fail to start (FTS), fail to load (FTL) and fail to run (FTR). Common cause events exist for each of the three failure modes of the EDG in the following combinations:

1) Failure of all three EDGs,
2) Failure of EDG-A and EDG-B,
3) Failure of EDG-A and EDG-C,
4) Failure of EDG-B and EDG-C.

This results in a total of 12 common cause events.

Assume the maximum [FV/UR] resulted from the FTS failure mode, then the FV_{cc} used in equation 4 would be the sum of the four common cause FTS events for the combinations listed above.

It is recognized that there is significant variation in the methods used to model common cause. It is common that the 12 individual common cause events described above are combined into a fewer number of events in many PRAs. Correct application of the plant specific method would, in this case, require the decomposition of the combined events and their related FV values into the individual parts. This can be accomplished by application of the following proportionality:

$$FV_{part} = FV_{total} \times \frac{UR_{part}}{UR_{total}} \qquad \text{Eq. 5}$$

Returning to the example above, assume that common cause was modeled in the PRA by combining all failure modes for each specific combination of equipment modeled. Thus there would be four common cause events corresponding to the four possible equipment groupings listed above, but each of the common cause events would include the three failure modes FTS, FTL and FTR. Again, assume the FTS independent failure mode is the event that resulted in the maximum [FV/UR] ratio. The FVcc value to be used would be determined by determining the FTS contribution for each of the four common cause events. In the case of the event representing failure of all three EDGs this would be determined from

$$FV_{FTSABC} = FV_{ABC} \times \frac{UR_{FTSABC}}{UR_{ABC}}$$

Where,

FV_{FTSABC} = the FV for the FTS failure mode and the failure of all three EDGs

FV_{ABC} = the event from the PRA representing the failure of all three EDGs due to all failure modes

UR_{FTSABC} = the failure probability for a FTS of all three EDGs, and

UR_{ABC} = the failure probability for all failure modes for the failure of all three EDGs.

After this same calculation was performed for the remaining three common cause events, the value for FV_{CC} to be used in equation 4 would then be calculated from:

$$FV_{cc} = FV_{FTSABC} + FV_{FTSAB} + FV_{FTSAC} + FV_{FTSBC}$$

This value is used in equation 4 to determine the value of A. The final quantity used in equation 3 is given by:

$$[FV/UR]_{\max} = A * [FV/UR]_{ind}$$

In this case the individual values on the right hand side of the equation above are input to CDE.

2.3.3. Birnbaum Importance

One of the rules used for determining the valves to be monitored in this performance indicator permitted the exclusion of valves with a Birnbaum importance less than 1.0e-

06. To apply this screening rule the Birnbaum importance is calculated from the values derived in this section as:

$B = CDF*A*[FV/UR]_{ind} = CDF*[FV/UR]_{max}$

2.3.4. Calculation of UR_{Bc}

Component unreliability is calculated by:

$$URBc = PD + \lambda Tm \quad \text{Eq 6}$$

Where:

P_D is the component failure on demand probability calculated based on data collected during the previous 12 quarters,

λ is the component failure rate (per hour) for failure to run calculated based on data collected during the previous 12 quarters,

and

T_m is the risk-significant mission time for the component based on plant specific PRA model assumptions. *Where there is more than one mission time for different initiating events or sequences (e.g., turbine-driven AFW pump for loss of offsite power with recovery versus loss of feedwater), the longest mission time is to be used.*

NOTE:

For valves only the P_D term applies

For pumps $P_D + \lambda\, T_m$ applies

For diesels $P_{D\,start} + P_{D\,load\,run} + \lambda\, T_m$ applies

The first term on the right side of equation 6 is calculated as follows.[6]

$$PD = \frac{(Nd + a)}{(a + b + D)} \quad \text{Eq. 7}$$

where in this expression:

N_d is the total number of failures on demand during the previous 12 quarters,

D is the total number of demands during the previous 12 quarters determined in section 2.2.1

The values a and b are parameters of the industry prior, derived from industry experience (see Table 4).

[6] Atwood, Corwin L., Constrained noninformative priors in risk assessment, *Reliability Engineering and System Safety*, 53 (1996; 37-46)

In the calculation of equation 5 the numbers of demands and failures is the sum of all demands and failures for similar components within each system. Do not sum across units for a multi-unit plant. For example, for a plant with two trains of Emergency Diesel Generators, the demands and failures for both trains would be added together for one evaluation of P_D which would be used for both trains of EDGs.

In the second term on the right side of equation 6, λ is calculated as follows.

$$\lambda = \frac{(Nr + a)}{(Tr + b)} \qquad \text{Eq. 8}$$

where:

N_r is the total number of failures to run during the previous 12 quarters (determined in section 2.2.2),

T_r is the total number of run hours during the previous 12 quarters (determined in section 2.2.1)

and

a and b are parameters of the industry prior, derived from industry experience (see Table 4).

In the calculation of equation 8 the numbers of demands and run hours is the sum of all run hours and failures for similar components within each system. Do not sum across units for a multi-unit plant. For example, a plant with two trains of Emergency Diesel Generators, the run hours and failures for both trains would be added together for one evaluation of λ which would be used for both trains of EDGs.

2.3.5. Baseline Unreliability Values

The baseline values for unreliability are contained in Table 4 and remain fixed.

Table 4. Industry Priors and Parameters for Unreliability

Component	Failure Mode	a [a]	b [a]	Industry MeanValue [b] URBLC
Circuit Breaker		4.99E-1	6.23E+2	8.00E-4
Motor-operated valve	Fail to open (or close)	4.99E-1	7.12E+2	7.00E-4
Air-operated valve	Fail to open (or close)	4.98E-1	4.98E+2	1.00E-3
Motor-driven pump,	Fail to start	4.97E-1	2.61E+2	1.90E-3

Component	Failure Mode	a [a]	b [a]	Industry MeanValue [b] URBLC
standby	Fail to run	5.00E-1	1.00E+4	5.00E-5
Motor-driven pump, running or alternating	Fail to start	4.98E-1	4.98E+2	1.00E-3
	Fail to run	5.00E-1	1.00E+5	5.00E-6
Turbine-driven pump, AFWS	Fail to start	4.85E-1	5.33E+1	9.00E-3
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Turbine-driven pump, HPCI or RCIC	Fail to start	4.78E-1	3.63E+1	1.30E-2
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Diesel-driven pump, AFWS	Fail to start	4.80E-1	3.95E+1	1.20E-2
	Fail to run	5.00E-1	2.50E+3	2.00E-4
Emergency diesel generator	Fail to start	4.92E-1	9.79E+1	5.00E-3
	Fail to load/run	4.95E-1	1.64E+2	3.00E-3
	Fail to run	5.00E-1	6.25E+2	8.00E-4

NOTE: THIS TABLE IS SUBJECT TO UPDATE AFTER THE FIRST DATA SUBMISSION IN APRIL 2006

a. A constrained, non-informative prior is assumed. For failure to run events, a = 0.5 and b = (a)/(mean rate). For failure upon demand events, a is a function of the mean probability:

Mean Probability	a
0.0 to 0.0025	0.50
>0.0025 to 0.010	0.49
>0.010 to 0.016	0.48
>0.016 to 0.023	0.47
>0.023 to 0.027	0.46

Then b = (a)(1.0 - mean probability)/(mean probability).

b. Failure to run events occurring within the first hour of operation are included within the fail to start failure mode. Failure to run events occurring after the first hour of operation are included within the fail to run failure mode.

c. Fail to load and run for one hour was calculated from the failure to run data in the report indicated. The failure rate for 0.0 to 0.5 hour (3.3E-3/h) multiplied by 0.5 hour, was added to the failure rate for 0.5 to 14 hours (2.3E-4/h) multiplied by 0.5 hour.

3. Establishing Statistical Significance

What is desired here is a short, non-technical explanation and reference to NRC technical report and CDE.

4. Calculation of System Component Performance Limits

The mitigating systems chosen to be monitored are generally the most important systems in nuclear power stations. However, in some cases the system may not be as important at a specific station. This is generally due to specific features at a plant, such as diverse methods of achieving the same function as the monitored system. In these cases a significant degradation in performance could occur before the risk significance reached a point where the MSPI would cross the white boundary. In cases such as this it is not likely that the performance degradation would be limited to that one system and may well involve cross cutting issues that would potentially affect the performance of other mitigating systems.

A performance based criterion for determining degraded performance is used as an additional decision criteria for determining that performance of a mitigating system has degraded to the white band. This decision is based on deviation of system performance from expected performance. The decision criterion was developed such that a system is placed in the white performance band when there is high confidence that system performance has degraded even though MSPI < 1.0e-06.

The criterion is applied to each component type in a system. If the number of failures in a 36 month period for a component type exceeds a performance based limit, then the system is considered to be performing at a white level, regardless of the MSPI calculated value. The performance based limit is calculated in two steps:

1. Determine the expected number of failures for a component type and
2. Calculate the performance limit from this value.

The expected number of failures is calculated from the relation

$$Fe = Nd * p + \lambda * Tr$$

Where:

N_d is the number of demands

p is the probability of failure on demand

λ is the failure rate

T_r is the runtime of the component

This value is used in the following expression to determine the maximum number of failures:

$$Fm = 4.65 * Fe + 4.2$$

If the actual number of failures (Fa) of a similar group of components (components that are grouped for the purpose of pooling data) within a system in a 36 month period exceeds Fm, then the system is placed in the largest of the white performance level or the level dictated by the MSPI calculation.

This calculation will be performed by the CDE software, no additional input values are required.

5. Additional Guidance for Specific Systems

This guidance provides typical system scopes. Individual plants should include those systems employed at their plant that are necessary to satisfy the specific risk-significant functions described below and reflected in their PRAs.

Emergency AC Power Systems

Scope

The function monitored for the emergency AC power system is the ability of the emergency generators to provide AC power to the class 1E buses upon a loss of off-site power while the reactor is critical, including post-accident conditions. The emergency AC power system is typically comprised of two or more independent emergency generators that provide AC power to class 1E buses following a loss of off-site power. The emergency generator dedicated to providing AC power to the high pressure core spray system in BWRs is not within the scope of emergency AC power.

The electrical circuit breaker(s) that connect(s) an emergency generator to the class 1E buses that are normally served by that emergency generator are considered to be part of the emergency generator train.

Emergency generators that are not safety grade, or that serve a backup role only (e.g., an alternate AC power source), are not included in the performance reporting.

Train Determination

The number of emergency AC power system trains for a unit is equal to the number of class 1E emergency generators that are available to power safe-shutdown loads in the event of a loss of off-site power for that unit. There are three typical configurations for EDGs at a multi-unit station:

1. EDGs dedicated to only one unit.
2. One or more EDGs are available to "swing" to either unit
3. All EDGs can supply all units

For configuration 1, the number of trains for a unit is equal to the number of EDGs dedicated to the unit. For configuration 2, the number of trains for a unit is equal to the number of dedicated EDGs for that unit plus the number of "swing" EDGs available to that unit (i.e., The "swing" EDGs are included in the train count for each unit). For configuration 3, the number of trains is equal to the number of EDGs.

Clarifying Notes

The emergency diesel generators are not considered to be available during the following portions of periodic surveillance tests unless recovery from the test configuration during accident conditions is virtually certain, as described in "Credit for operator recovery actions during testing," can be satisfied; or the duration of the condition is less than fifteen minutes per train at one time:

- Load-run testing
- Barring

An EDG is not considered to have failed due to any of the following events:

- spurious operation of a trip that would be bypassed in a loss of offsite power event
- malfunction of equipment that is not required to operate during a loss of offsite power event (e.g., circuitry used to synchronize the EDG with off-site power sources)
- failure to start because a redundant portion of the starting system was intentionally disabled for test purposes, if followed by a successful start with the starting system in its normal alignment

Air compressors are not part of the EDG boundary. However, air receivers that provide starting air for the diesel are included in the EDG boundary.

If an EDG has a dedicated battery independent of the station's normal DC distribution system, the dedicated battery is included in the EDG system boundary.

The fuel transfer pumps are not considered to be a monitored component in the EDG system. They are considered to be a support system.

BWR High Pressure Injection Systems

(High Pressure Coolant Injection, High Pressure Core Spray, and Feedwater Coolant Injection)

Scope

These systems function at high pressure to maintain reactor coolant inventory and to remove decay heat following a small-break Loss of Coolant Accident (LOCA) event or a loss of main feedwater event.

The function monitored for the indicator is the ability of the monitored system to take suction from the suppression pool (and from the condensate storage tank, if credited in the plant's accident analysis) and inject into the reactor vessel.

Plants should monitor either the high-pressure coolant injection (HPCI), the high-pressure core spray (HPCS), or the feedwater coolant injection (FWCI) system, whichever is installed. The turbine and governor (or motor-driven FWCI pumps), and associated piping and valves for turbine steam supply and exhaust are within the scope of these systems. Valves in the feedwater line are not considered within the scope of these systems.

The emergency generator dedicated to providing AC power to the high-pressure core spray system is included in the scope of the HPCS. The HPCS system typically includes a "water leg" pump to prevent water hammer in the HPCS piping to the reactor vessel. The "water leg" pump and valves in the "water leg" pump flow path are ancillary components and are not included in the scope of the HPCS system. Unavailability is not included while critical if the system is below steam pressure specified in technical specifications at which the system can be operated.

Train Determination

The HPCI and HPCS systems are considered single-train systems. The booster pump and other small pumps are ancillary components not used in determining the number of trains. The effect of these pumps on system performance is included in the system indicator to the extent their failure detracts from the ability of the system to perform its risk-significant function. For the FWCI system, the number of trains is determined by the number of feedwater pumps. The number of condensate and feedwater booster pumps are not used to determine the number of trains.

Reactor Core Isolation Cooling

(or Isolation Condenser)

Scope

This system functions at high pressure to remove decay heat following a loss of main feedwater event. The RCIC system also functions to maintain reactor coolant inventory following a very small LOCA event.

The function monitored for the indicator is the ability of the RCIC system to cool the reactor vessel core and provide makeup water by taking a suction from either the condensate storage tank or the suppression pool and injecting at rated pressure and flow into the reactor vessel.

The Reactor Core Isolation Cooling (RCIC) system turbine, governor, and associated piping and valves for steam supply and exhaust are within the scope of the RCIC system. Valves in the feedwater line are not considered within the scope of the RCIC system.

The Isolation Condenser and inlet valves are within the scope of Isolation Condenser system. Unavailability is not included while critical if the system is below steam pressure specified in technical specifications at which the system can be operated.

Train Determination

The RCIC system is considered a single-train system. The condensate and vacuum pumps are ancillary components not used in determining the number of trains. The effect of these pumps on RCIC performance is included in the system indicator to the extent that a component failure results in an inability of the system to perform its risk-significant function.

BWR Residual Heat Removal Systems

Scope

The functions monitored for the BWR residual heat removal (RHR) system are the ability of the RHR system to remove heat from the suppression pool, provide low pressure coolant injection, and provide post-accident decay heat removal. The pumps, heat exchangers, and associated piping and valves for those functions are included in the scope of the RHR system.

Train Determination

The number of trains in the RHR system is determined by the number of parallel RHR heat exchangers.

PWR High Pressure Safety Injection Systems

Scope

These systems are used primarily to maintain reactor coolant inventory at high pressures following a loss of reactor coolant. HPSI system operation following a small-break LOCA involves transferring an initial supply of water from the refueling water storage tank (RWST) to cold leg piping of the reactor coolant system. Once the RWST inventory is depleted, recirculation of water from the reactor building emergency sump is required. The function monitored for HPSI is the ability of a HPSI train to take a suction from the primary water source (typically, a borated water tank), or from the containment emergency sump, and inject into the reactor coolant system at rated flow and pressure.

The scope includes the pumps and associated piping and valves from both the refueling water storage tank and from the containment sump to the pumps, and from the pumps into the reactor coolant system piping. For plants where the high-pressure injection pump takes suction from the residual heat removal pumps, the residual heat removal pump discharge header isolation valve to the HPSI pump suction is included in the scope of HPSI system. Some components may be included in the scope of more than one train. For example, cold-leg injection lines may be fed from a common header that is supplied by both HPSI trains. In these cases, the effects of testing or component failures in an injection line should be reported in both trains.

Train Determination

In general, the number of HPSI system trains is defined by the number of high head injection paths that provide cold-leg and/or hot-leg injection capability, as applicable.

For Babcock and Wilcox (B&W) reactors, the design features centrifugal pumps used for high pressure injection (about 2,500 psig) and no hot-leg injection path. Recirculation from the containment sump requires operation of pumps in the residual heat removal system. They are typically a two-train system, with an installed spare pump (depending on plant-specific design) that can be aligned to either train.

For two-loop Westinghouse plants, the pumps operate at a lower pressure (about 1600 psig) and there may be a hot-leg injection path in addition to a cold-leg injection path (both are included as a part of the train).

For Westinghouse three-loop plants, the design features three centrifugal pumps that operate at high pressure (about 2500 psig), a cold-leg injection path through the BIT (with two trains of redundant valves), an alternate cold-leg injection path, and two hot-leg injection paths. One of the pumps is considered an installed spare. Recirculation is provided by taking suction from the RHR pump discharges. A train consists of a pump, the pump suction valves and boron injection tank (BIT) injection line valves electrically associated with the pump, and the associated hot-leg injection path. The alternate cold-leg injection path is required for recirculation, and should be included in the train with which its isolation valve is electrically associated. This represents a two-train HPSI system.

For Four-loop Westinghouse plants, the design features two centrifugal pumps that operate at high pressure (about 2500 psig), two centrifugal pumps that operate at an intermediate pressure (about 1600 psig), a BIT injection path (with two trains of injection valves), a cold-leg safety injection path, and two hot-leg injection paths. Recirculation is provided by taking suction from the RHR pump discharges. Each of two high pressure trains is comprised of a high pressure centrifugal pump, the pump suction valves and BIT valves that are electrically associated with the pump. Each of two intermediate pressure trains is comprised of the safety injection pump, the suction valves and the hot-leg injection valves electrically associated with the pump. The cold-leg safety injection path can be fed with either safety injection pump, thus it should be associated with both intermediate pressure trains. This HPSI system is considered a four-train system for monitoring purposes.

For Combustion Engineering (CE) plants, the design features two or three centrifugal pumps that operate at intermediate pressure (about 1300 psig) and provide flow to two or four cold-leg injection paths or two hot-leg injection paths. In most designs, the HPSI pumps take suction directly from the containment sump for recirculation. In these cases, the sump suction valves are included within the scope of the HPSI system. This is a two-train system (two trains of combined cold-leg and hot-leg injection capability). One of the three pumps is typically an installed spare that can be aligned to either train or only to one of the trains (depending on plant-specific design).

PWR Auxiliary Feedwater Systems

Scope

The AFW system provides decay heat removal via the steam generators to cool down and depressurize the reactor coolant system following a reactor trip. The AFW system is assumed to be required for an extended period of operation during which the initial supply of water from the condensate storage tank is depleted and water from an alternative water source (e.g., the service water system) is required. Therefore components in the flow paths from both of these water sources are included; however, the alternative water source (e.g., service water system) is not included.

The function monitored for the indicator is the ability of the AFW system to take a suction from the primary water source (typically, the condensate storage tank) or, if required, from an emergency source (typically, a lake or river via the service water system) and inject into at least one steam generator at rated flow and pressure.

The scope of the auxiliary feedwater (AFW) or emergency feedwater (EFW) systems includes the pumps and the components in the flow paths from the condensate storage tank and, if required, the valve(s) that connect the alternative water source to the auxiliary feedwater system. Pumps included in the Technical Specifications are included in the scope of this indicator. Startup feedwater pumps are not included in the scope of this indicator.

Train Determination

The number of trains is determined primarily by the number of parallel pumps. For example, a system with three pumps is defined as a three-train system, whether it feeds two, three, or four injection lines, and regardless of the flow capacity of the pumps. Some components may be included in the scope of more than one train. For example, one set of flow regulating valves and isolation valves in a three-pump, two-steam generator system are included in the motor-driven pump train with which they are electrically associated, but they are also included (along with the redundant set of valves) in the turbine-driven pump train. In these instances, the effects of testing or failure of the valves should be reported in both affected trains. Similarly, when two trains provide flow to a common header, the effect of isolation or flow regulating valve failures in paths connected to the header should be considered in both trains.

PWR Residual Heat Removal System *(Check for any needed change wrt CE plants and Surry, N. Anna and Beaver Valley)*

Scope

The functions monitored for the PWR residual heat removal (RHR) system are those that are required to be available when the reactor is critical. These typically include the low-pressure injection function and the post-accident recirculation mode used to cool and recirculate water from the containment sump following depletion of RWST inventory to provide post-accident decay heat removal. The pumps, heat exchangers, and associated piping and valves for those functions are included in the scope of the RHR system. Containment spray function should be included if it is identified as a risk-significant post accident decay heat removal function. Containment spray systems that only provide containment pressure control are not included.

Train Determination

The number of trains in the RHR system is determined by the number of parallel RHR heat exchangers. Some components are used to provide more than one function of RHR. If a component cannot perform as designed, rendering its associated train incapable of meeting one of the risk-significant functions, then the train is considered to be failed. Unavailable hours would be reported as a result of the component failure.

Cooling Water Support System

Scope

The function of the cooling water support system is to provide for direct cooling of the components in the other monitored systems. It does not include indirect cooling provided by room coolers or other HVAC features.

Systems that provide this function typically include service water and component cooling water or their cooling water equivalents. Pumps, valves, heat exchangers and line segments that are necessary to provide cooling to the other monitored systems are included in the system scope up to, but not including, the last valve that connects the cooling water support system to a single component in another monitored system. This last valve is included in the other monitored system boundary. Service water systems are typically open "raw water" systems that use natural sources of water such as rivers, lakes or oceans. Component Cooling Water systems are typically closed "clean water" systems.

Valves in the cooling water support system that must close to ensure sufficient cooling to the other monitored system components to meet risk significant functions are included in the system boundary.

If a cooling water system provides cooling to only one monitored system, then it should be included in the scope of that monitored system.

Train Determination

The number of trains in the Cooling Water Support System will vary considerably from plant to plant. The way these functions are modeled in the plant-specific PRA will determine a logical approach for train determination. For example, if the PRA modeled separate pump and line segments, then the number of pumps and line segments would be the number of trains.

Clarifying Notes

Service water pump strainers and traveling screens are not considered to be monitored components and are therefore not part of URI. However, clogging of strainers and screens that render the train unavailable to perform its risk significant cooling function (which includes the risk-significant mission times) are included in UAI.

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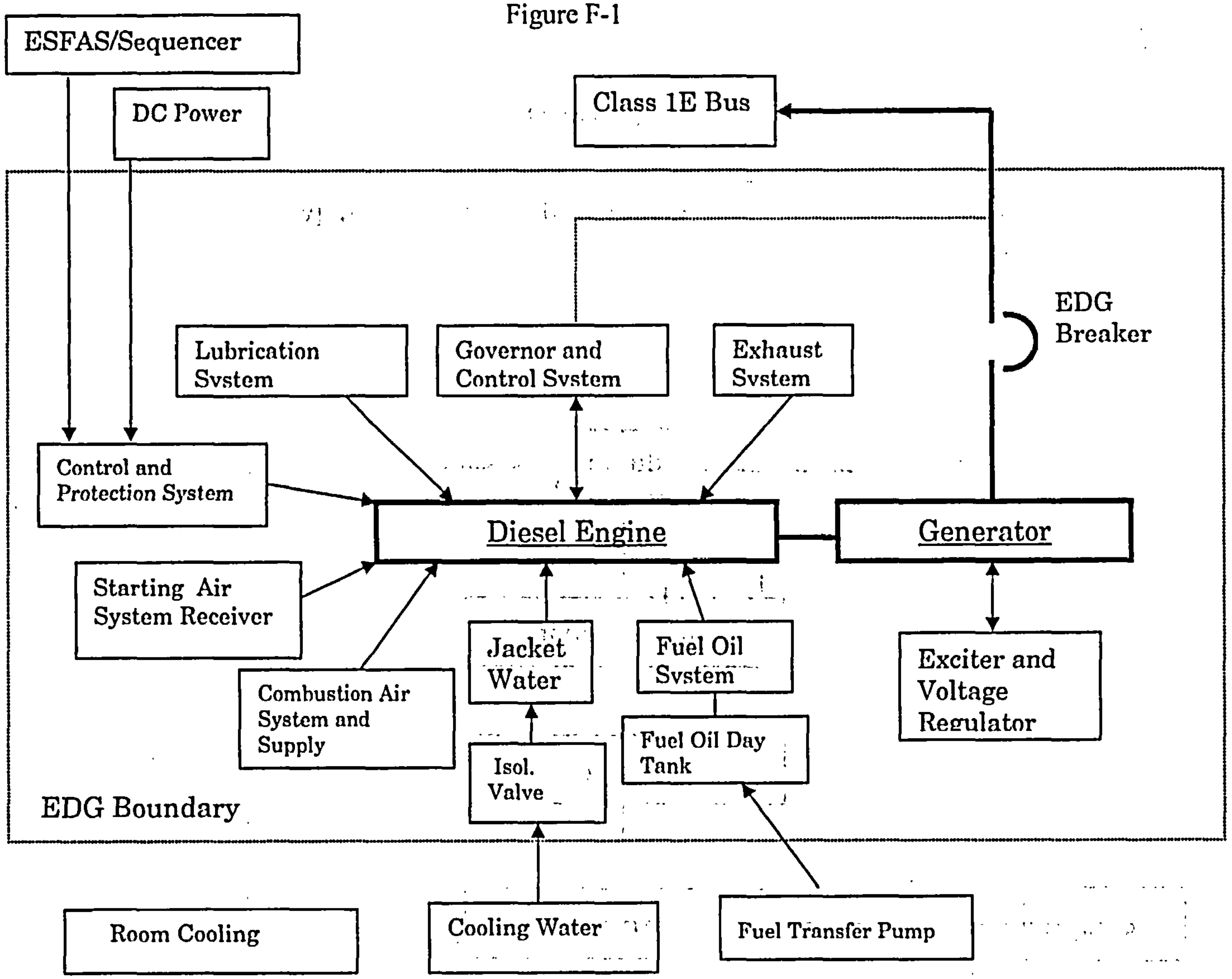
1
2

Figure F-1



3

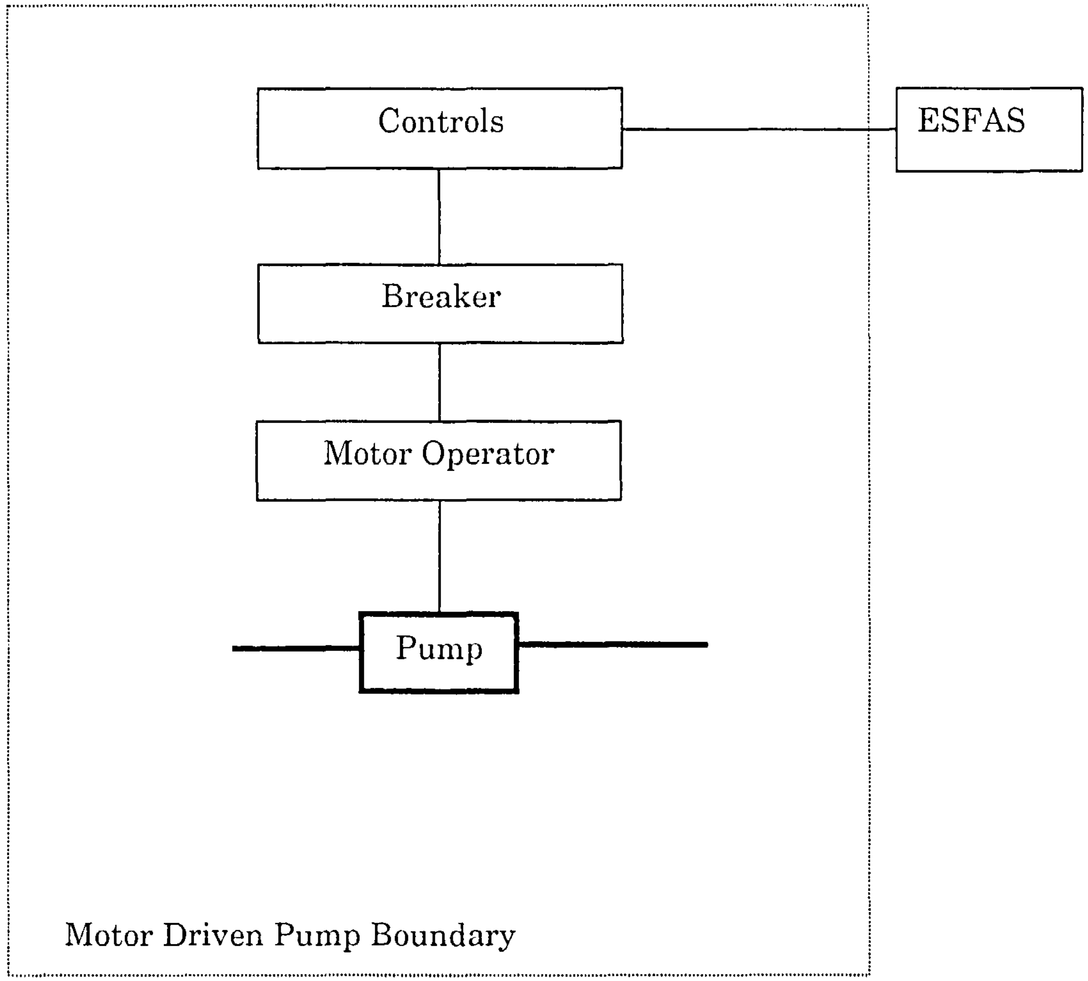

Controls
ESFAS
Breaker
Motor Operator
Pump
Motor Driven Pump Boundary

Figure F-2

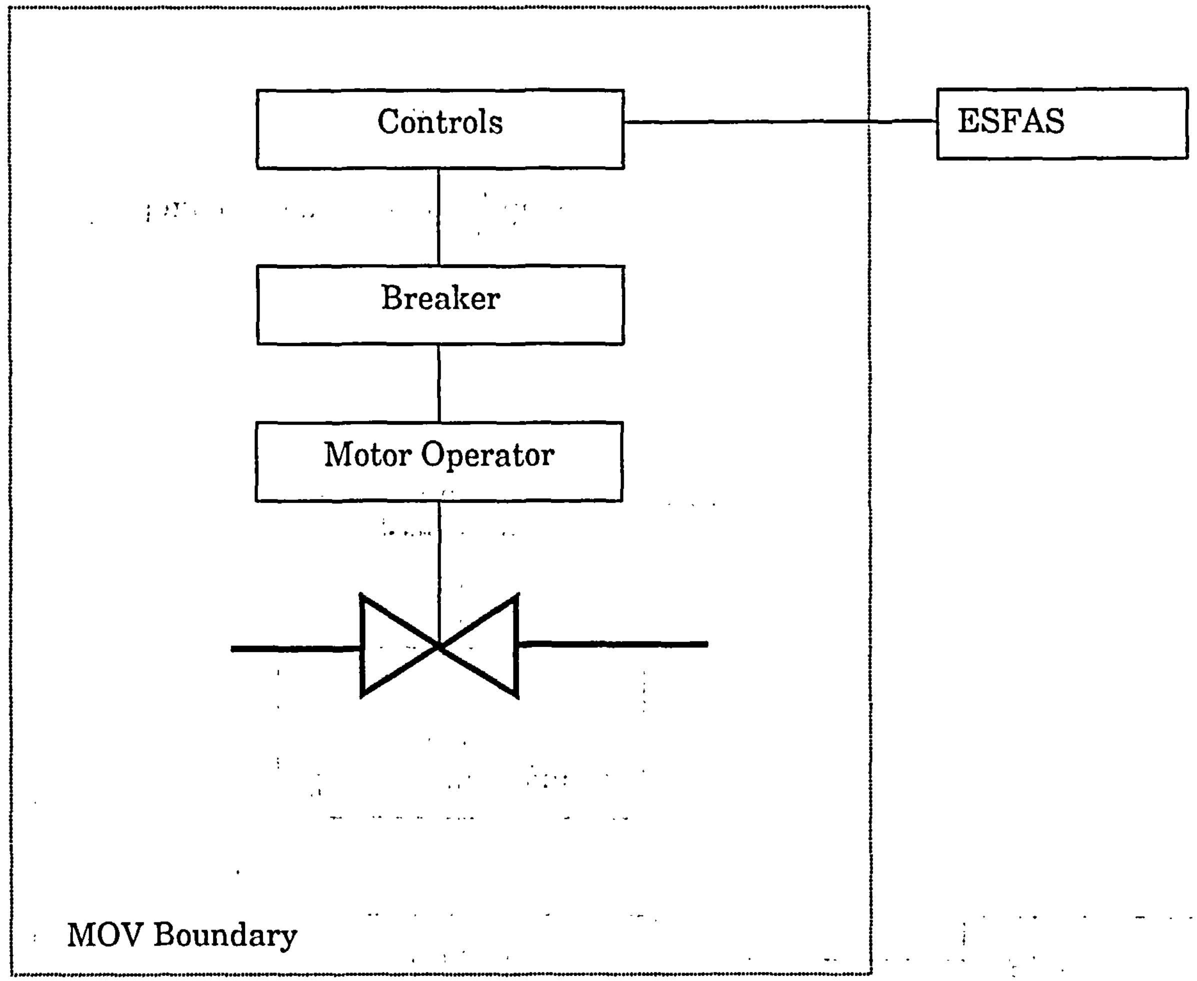


Figure F-3

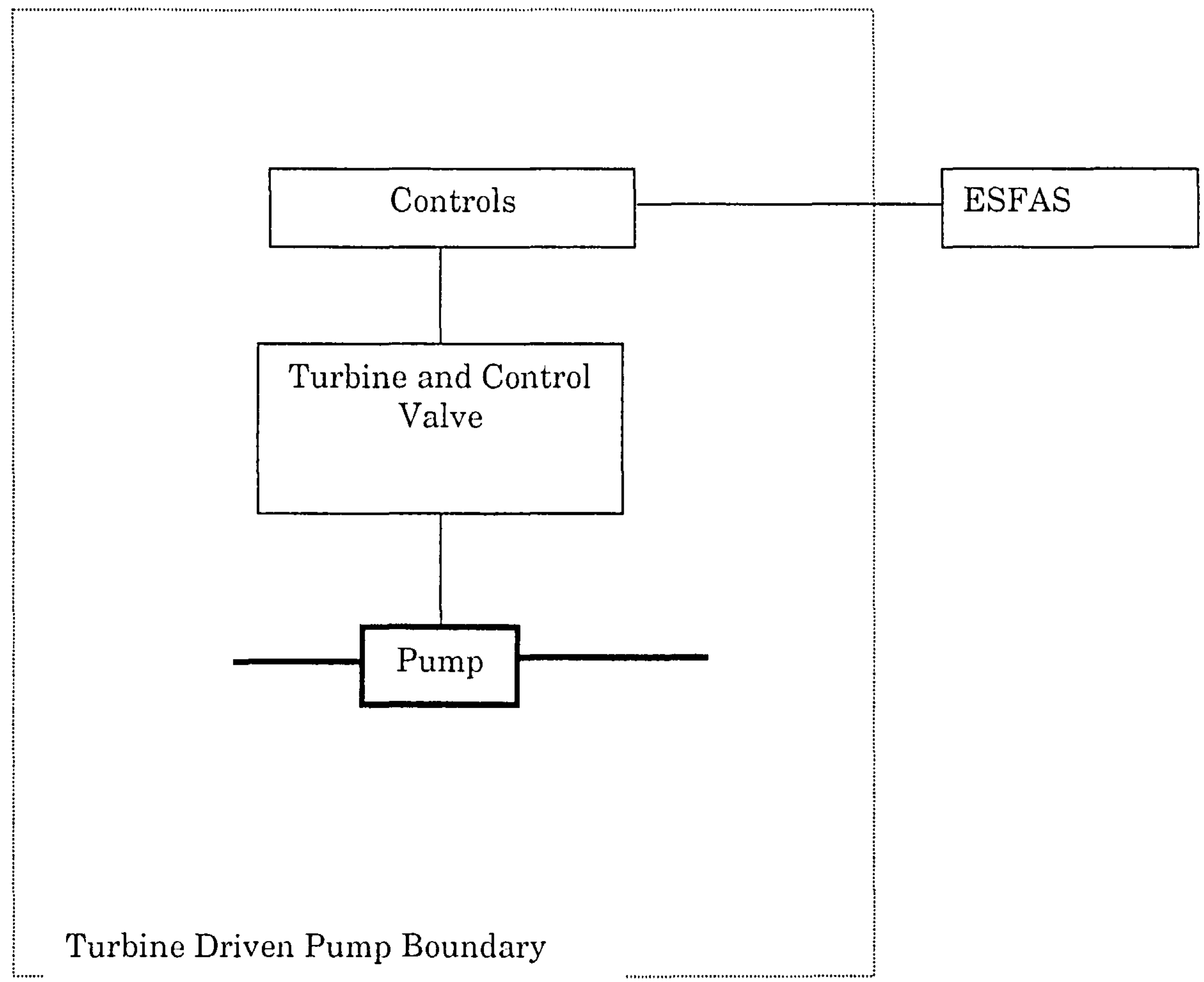

Controls
ESFAS
Turbine and Control Valve
Pump
Turbine Driven Pump Boundary

Figure F-4

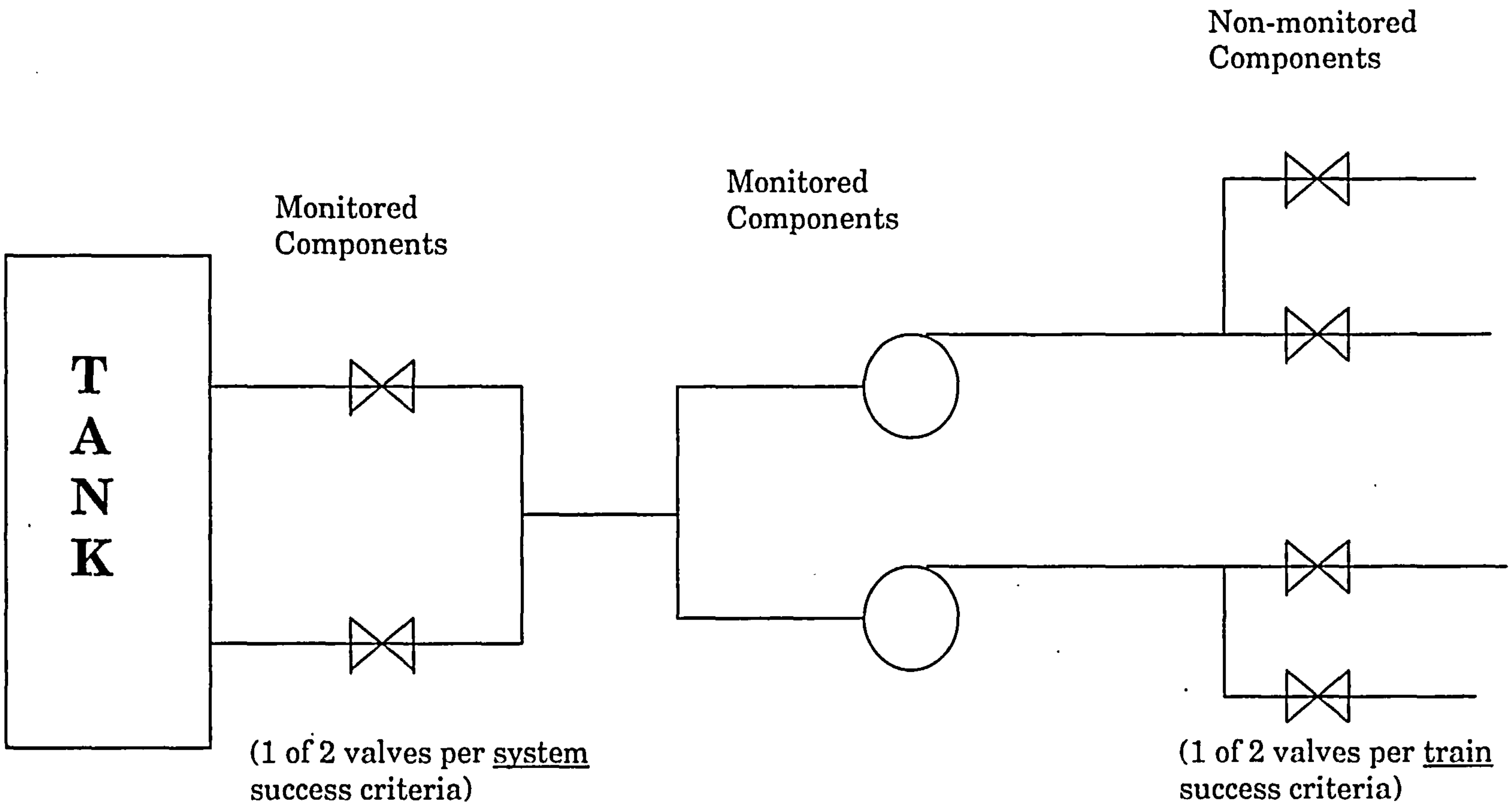

Non-monitored
Components
Monitored
Components
Monitored
Components
TANK
(1 of 2 valves per system
success criteria)
(1 of 2 valves per train
success criteria)

Figure F-5

NEI 99-02 Appendix G, MSPI Basis Document Development

To implement the Mitigating Systems Performance Index (MSPI), Licensees *will*~~shall~~ develop a plant specific basis document that documents the information and assumptions used to calculate the Reactor Oversight Program (ROP) MSPI. This basis document is necessary to support the NRC inspection process, and to record the assumptions and data used in developing the MSPI on each site.

The Basis document will have two major sections. The first described below will document the information used in developing the MSPI. The second section will document the conformance of the plant specific PRA to the requirements that are outlined in this appendix.

I. MSPI Data

The basis document ~~should be written to~~ provides a separate section for each monitored system as defined in Section 2.2 of NEI 99-02. The section for each monitored system ~~should~~ contains the following subsections:

A. System Boundaries

This section ~~shall~~ contains a description of the boundaries for each train of the monitored system. A plant drawing or figure (training type figure) should be included and marked adequately (i.e., highlighted trains) to show the boundaries. The guidance for determining the boundaries is provided in Appendix F, Section 1.1 of NEI 99-02.

B. Risk Significant Functions

This section ~~shall~~ lists the risk significant functions for each train of the monitored system. Risk Significant Functions are defined in section 2.2 of NEI 99-02. Additional detail is given in Appendix F, Section 2.1.1 and Section 5 "Additional Guidance for Specific Systems". A single list for the system may be used as long as any differences between trains are clearly identified. This section may also be combined with the section on Success Criteria if a combination of information into a table format is desired.

C. Success Criteria

This section ~~shall~~ documents the success criteria as defined in Section 2.2 of NEI 99-02 for each of the identified risk significant functions identified for the system. Additional detail is given in Appendix F, Section 2.1.1. The criteria used should be the documented PRA success criteria. Otherwise plant design basis values are used, and identified in this section. Where there are different success criteria for different functions or initiators, all should be recorded and the most restrictive shown as the one used.

D. Mission Time

This section ~~shall~~ documents the risk significant mission time as defined in Section 2.2 of NEI 99-02 for each of the identified risk significant functions identified for the system.

The default value of 24 hours should be used unless other values are used in the plant PRA, documented by the plant, and identified in this section.

E. Monitored Components

This section ~~shall~~ documents the selection of monitored components as defined in Appendix F, Section 2.1.2 of NEI 99-02 in each train of the monitored system. A listing of all monitored pumps, breakers and EDG's should be included in this section. A listing of AOV's and MOV's that change state to achieve the risk significant functions should be provided as potential monitored components. The basis for excluding valves in this list from monitoring should be provided. Component boundaries as described in Appendix F, Section 2.1.3 of NEI 99-02 should be included where appropriate.

F. Basis for Demands/*Run Times* (estimate or actual)

The determination of reliability largely relies on the values of demands, *run times* and failures of components to develop a failure rate. This section ~~shall~~ documents how the licensee will determine the demands on a component. Several methods may be used.

- Actual counting of demands/*run times* during the reporting period
- An estimate of demands/*run times* based on the number of times a procedure or maintenance activity is performed
- An estimate based on historical data over a year or more averaged for a quarterly average

The method used should be described and the basis information used documented.

G. PRA Information used in the MSPI

1. Unavailability FV and UA

This section ~~shall~~ includes a table or spreadsheet that lists the basic events for unavailability for each train of the monitored systems. This listing should include the probability, FV, and FV/probability ratio and text description of the basic event or component ID.

a) Unavailability Baseline Data

This section ~~shall~~ includes the baseline unavailability data by train for each monitored system. The discussion should include the basis for the baseline values used.

2. Unreliability FV and UR

This section ~~shall~~ includes a table or spreadsheet that lists the basic events for component failures for each monitored component. This listing should include the probability, FV, the common cause adjustment factor and FV/probability ratio and text description of the basic event or component ID.

a) Treatment of Support System Initiator

This section ~~should~~ documents whether the cooling water systems are an initiator or not. This *section* ~~section shall contain the~~*provides a* description of how the plant will include the support system initiator as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section.

b) Calculation of Common Cause Factor

This section ~~shall~~ contains the description of how the plant will determine the common cause factor as described in Appendix F of NEI 99-02. If an analysis is performed for a plant specific value, the calculation must be documented in accordance with plant processes and referred to here. The results should also be included in this section.

H. Assumptions

This section ~~shall~~ documents any specific assumptions made in determination of the MSPI information that may need to be documented. Causes for documentation in this section could be special methods of counting hours or runtimes based on plant specific designs or processes, or other instances not clearly covered by the guidance in NEI 99-02.

II. PRA REQUIREMENTS

A. INSERT THE PRA TECHNICAL ADEQUACY REQUIREMENTS DEVELOPED BY THE EXPERT PANEL HERE

B. DOCUMENT HOW THE PLANT PRA MEETS THE PRA TECHNICAL ADEQUACY REQUIREMENTS HERE