ENCLOSURE 2

MFN 13-081

NEDO-33075-A, Revision 8

Non-Proprietary Information– Class I (Public)

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GE Hitachi Nuclear Energy

NEDO-33075-A
Revision 8
DRF Section-0000-0130-0875 R4
November 2013

Non-Proprietary Information - Class I (Public)

LICENSING TOPICAL REPORT

GE HITACHI BOILING WATER REACTOR DETECT AND SUPPRESS SOLUTION – CONFIRMATION DENSITY

Juswald Vedovi

David G. Vreeland

Jun J. Yang

INFORMATION NOTICE

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GEH has received US patent #6,173,026 covering this subject matter.

IMPORTANT NOTICE REGARDING CONTENTS OF THIS REPORT

Please Read Carefully

November 14, 2013

Mr. Jerald G. Head
Senior Vice President, Regulatory Affairs
GE-Hitachi Nuclear Energy Americas LLC
P.O. Box 780, M/C A-18
Wilmington, NC 28401-0780

SUBJECT: FINAL SAFETY EVALUATION FOR GE HITACHI NUCLEAR ENERGY AMERICAS TOPICAL REPORT NEDC-33075P, REVISION 7, “GE HITACHI BOILING WATER REACTOR DETECT AND SUPPRESS SOLUTION - CONFIRMATION DENSITY” (TAC NO. ME6577)

Dear Mr. Head:

By letter dated June 10, 2011, GE-Hitachi Nuclear Energy Americas, LLC (GEH) submitted Topical Report (TR) NEDC-33075P, Revision 7, “GE Hitachi Boiling Water Reactor Detect and Suppress Solution - Confirmation Density” (Reference 1) to the U.S. Nuclear Regulatory Commission (NRC) staff for review. By letter dated August 3, 2013, an NRC draft safety evaluation (SE) regarding our approval of NEDE-33075P, Revision 7, was provided for your review and comment. By letter dated August 19, 2013, GEH commented on the draft SE. The NRC staff's disposition of GEH’s comments on the draft SE are discussed in the attachment to the final SE enclosed with this letter.

The enclosed final SE is available for use in future licensing actions, but the current version of NEDE-33075P, Revision 7, is not yet approved for referencing. We request that GEH publish new proprietary and non-proprietary versions of this TR for final NRC approval within three months of receipt of this letter. The approval version of this TR should include after the title page: this letter; the enclosed final SE; and historical review information such as NRC requests for additional information, and your responses. The approval version of the TR should also be marked with a “-A” (designating “approval version”) following the TR identification symbol.

Notice: Document transmitted herewith contains sensitive unclassified information. When separated from Enclosure 1, this document is decontrolled.

Upon receipt of the "-A" version of this TR, we will perform a final review of the document for historical review consistency and agreement with the enclosed final SE. Pending a successful outcome, we will then send a letter authorizing NEDE-33057P, Revision 7, for use in future licensing actions.

Sincerely,

/RA/

Sher Bahadur, Deputy Director
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

Project No. 710

Enclosures:
1. Proprietary Final SE
2. Non-Proprietary Final SE

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Upon receipt of the "-A" version of this TR, we will perform a final review of the document for historical review consistency and agreement with the enclosed final SE. Pending a successful outcome, we will then send a letter authorizing NEDE-33057P, Revision 7, for use in future licensing actions.

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* No significant changes from Draft SE input
** No significant changes from Revised Draft SE
*** Concurred via e-mail **NRR-043**

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FINAL SAFETY EVALUATION BY

THE OFFICE OF NUCLEAR REACTOR REGULATION

TOPICAL REPORT NEDC-33075P, REVISION 7

"GENERAL ELECTRIC BOILING WATER REACTOR DETECT AND SUPPRESS SOLUTION-CONFIRMATION DENSITY"

GE-HITACHI NUCLEAR ENERGY AMERICAS, LLC

PROJECT NO. 710

1.0 INTRODUCTION

By letter dated June 10, 2011, GE-Hitachi Nuclear Energy Americas, LLC (GEH) submitted Topical Report (TR) NEDC-33075P, Revision 7, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution - Confirmation Density" (Reference 1,) to the U.S. Nuclear Regulatory Commission (NRC) staff for review. NEDC-33075P, Revision 7, defines the licensing basis and reload applications for the "Detect and Suppress Solution - Confirmation Density" (DSS-CD) methodology. DSS-CD is a type of long-term stability solution previously approved by the NRC staff (References 2-3) that has features similar to the previously approved Solution III (References 3-5). Revision 7 of NEDC-33075P includes a transition from TRACG02/PANAC10 to TRACG04/PANAC11 GEH methodologies and clarification of several items that were discovered during implementation. This TR replaces the currently approved version, NEDC-33075P-A, Revision 6 (Reference 2).

With NEDC-33075P, Revision 7 (Reference 1), GEH requested an incremental review and approval of the improvements to the licensing basis for DSS-CD applications and other changes implemented since Revision 6. GEH requested review and approval of DSS-CD applications for GE BWR/3-6 product lines, GE14 and earlier GE fuel designs, and operating envelopes up to and including Extended Power Uprate (EPU) and Maximum Extended Load Line Limit Analysis Plus (MELLLA+).

TRACG04 applicability to DSS-CD calculations is documented in a separate TR, NEDE-33147P-A, Revision 4 (Reference 6). The "Delta CPR [critical power ratio] over Initial MCPR [minimum critical power ratio] Versus Oscillation Magnitude (DIVOM)" methodology using TRACG04 is documented in another TR, NEDO-32465 Supplement 1 (Reference 7). TR NEDO-32465, Supplement 1 is still under NRC staff review.

The NRC staff was assisted in this review by staff from Oak Ridge National Laboratory (ORNL). The NRC staff's review is based on the subject TR and its previous revisions, requests for additional information (RAIs), and information obtained during meetings with GEH to clarify and supplement these RAIs. The main conclusion from this review is that the proposed DSS-CD methodology provides protection against specified acceptable fuel design limits (SAFDLs) in the case of instabilities, even when operating the reactor in the EPU or MELLLA+ domains.
The NRC staff is currently evaluating the TRACG04 models for post-critical heat flux (CHF) heat

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transfer, dryout, and rewet, including the correlations for stable film boiling temperature (Tmin) and the quench front model (Reference 8). This SE documents the NRC staff's review regarding the application of TRACG04 for DSS-CD, where calculations are not analyzed past the point of CHF; therefore the approval of TRACG04 for DSS-CD does not imply the approval of the TRACG04 post-CHF models.

1.1. Background

Following the March 1988 instability event at a LaSalle County Station boiling water reactor (BWR), the BWR Owners' Group (BWROG) initiated a task to investigate actions that industry should take to resolve the stability issue as an operational concern. Through analysis, the BWROG found that the existing plant protection system, which was based on a scram on high average power range monitor (APRM) signal, may not provide enough protection against out-of-phase modes of instability; thus, the BWROG decided that a new automatic instability suppression function was required as a long-term solution and that this function should have a rapid and automatic response which does not rely on operator action.

The BWROG submitted and the NRC staff approved three different long-term stability options (Reference 3). It is up to the individual licensees to choose which solution will be implemented in their reactor. These options can be summarized as follows:

I. Exclusion Region. A region outside which instabilities are very unlikely is calculated for each representative plant type using well-defined procedures. If the reactor is operated inside this exclusion region, an automatic protective action is initiated to exit the region. This action is based exclusively on power and flow measurements, and the presence of oscillations is not required for its initiation. Two concepts of Solution I were submitted by the BWROG and approved by the NRC staff:

I-A Immediate protection action (either scram or select rod insert) upon entrance to the exclusion region.

I-D Some small-core plants with tight inlet orifices have a reduced likelihood of out-of-phase instabilities. For these plants, the existing flow-biased high APRM scram provides a detect and suppress function to avoid safety limits violation for the expected instability mode. In addition, administrative controls are proposed to maintain the reactor outside the exclusion region.

II. Quadrant-Based APRM Scram. In a BWR/2, the quadrant-based APRM is capable of detecting both in-phase and out-of-phase oscillations with sufficient sensitivity to initiate automatic protective action to suppress the oscillations before safety margins are compromised.

III. LPRM-Based Detect and Suppress. Local power range monitor (LPRM) signals or combinations of a small number of LPRMs are analyzed on-line by using three diverse algorithms. If any of the algorithms detects an instability, automatic protective action is taken to suppress the oscillations before safety margins are compromised.

All of the above solutions have been implemented in commercial nuclear power plants in the U. S. Nevertheless there are three significant areas of consideration, which merit a revisit of these long-term solutions. These areas are: (a) deficiencies identified in the CPR versus oscillation amplitude correlation used for detect and suppress solutions (i.e., the DIVOM correlation,) which resulted in a Title 10 of the *Code of Federal Regulations* (10 CFR) Part 21 notification, (b) proposed increases in power density, and (c) lessons learned from instability events that occurred at Nine Mile Point Nuclear Station, Unit 2 (hereafter, “Nine Mile Point 2”) in July 2003 and Perry Nuclear Power Plant, Unit 1 (hereafter, “Perry”) in December 2004.

The DIVOM correlation is used to estimate the delta CPR as a function of oscillation amplitude, and it is required to select the scram set point for detect and suppress solutions. The DIVOM correlation was approved on the basis that it would be bounding for all reasonable circumstances; however, later analysis demonstrated that some plant-specific calculations result in larger loss of CPR margin than the DIVOM prediction. Therefore, the generic DIVOM curve may be non-conservative for some plant applications. A non-conservative DIVOM curve would then result in stability-related setpoints that would not guarantee that SAFDLs would be maintained if a limiting instability event were to occur. This potential for a non-conservative DIVOM curve made Solution III invalid as a viable long-term solution, unless cycle-specific DIVOM correlations were used, which is the approach used by most plants today.

In recent years, the industry has been moving to reactor operation at higher and higher power densities and power-to-flow ratios. This operation is, in principle, detrimental to the stability characteristics of the reactor and results in two consequences: (a) it increases the probability of instability events, and (b) it increases the severity of the event should it occur (e.g., larger amplitude oscillations). Indeed, simulations of two recirculation pump trip (2RPT) transients initiated at MELLLA+ conditions (80 percent flow and 120 percent original licensed thermal power) indicate that instabilities of sufficiently large amplitude to compromise the safety limit MCPR (SLMCPR) in short time are not only possible, but very likely.

Since implementation of the long-term solutions, instability events have occurred at two U.S. plants: Nine Mile Point 2 in July 2003 and Perry in December 2004. Both events occurred in Solution III plants. Some deficiencies were identified in the performance of Solution III for the Nine Mile Point 2 event, resulting in a 10 CFR Part 21 notification. The deficiencies were related to the adjustable parameters for period-based detection, which are now recommended to be placed at their most sensitive settings. Most parameter settings for the long-term solutions are evaluated on a plant-specific basis by collecting noise data over a relatively long period of time. The parameters are adjusted during this trial period until normal plant transients do not trigger the stability detection algorithms. In Nine Mile Point 2, these parameters had been set to be fairly insensitive to avoid spurious actuations; however, this resulted in continuous resetting of the confirmation count because the Nine Mile Point 2 oscillation was very small in magnitude. In spite of stability solution deficiencies that were identified after careful analysis of the event data, Solution III automatically initiated a scram of the reactor and the SLMCPR was never compromised in the Nine Mile Point 2 event. The Perry event resulted from a malfunctioning valve, which triggered scram actuation by Solution III without compromising the SLMCPR.

2.0 REGULATORY EVALUATION

The DSS-CD design provides automatic detection and suppression of reactor instability and minimizes reliance on the operator to suppress instability events. The “Confirmation Density Algorithm” (CDA) is designed to recognize an instability and initiate control rod insertion before the power oscillations increase much above the noise level. The DSS-CD solution and its related licensing basis were developed to comply with the requirements of General Design Criteria (GDC) 10 and 12 in Part 50 of 10 CFR Part 50, Appendix A, “General Design Criteria for Nuclear Power Plants.”

Criterion 10, "Reactor design," requires that:

> The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Criterion 12, "Suppression of reactor power oscillations," requires that:

> The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

To ensure compliance with GDC 10 and 12, the NRC staff confirms that the thermal and hydraulic design of the core and the reactor coolant system has been accomplished using acceptable analytical methods, provides acceptable safety margins from conditions that could lead to fuel damage during normal reactor operation and anticipated operational occurrences, and is not susceptible to thermal-hydraulic instability or can be reliably and readily detected and suppressed. Regulatory guidance for the review of the thermal and hydraulic design and the suppression of reactor power oscillations is provided in NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (SRP) Section 4.4, "Thermal and Hydraulic Design," and SRP Section 15.9, "BWR Core Stability." As prescribed in NUREG-0800, Chapter 4, the NRC staff will confirm that the licensee performs the plant-specific trip setpoint calculations using NRC-approved methodologies. SRP Section 15.9 describes review procedures to evaluate the possibility of thermal-hydraulic instability in BWRs, analytical methods and codes to predict the stability characteristics of BWRs, and the use of approved long-term stability solutions.

3.0 <u>TECHNICAL EVALUATION</u>

3.1. Solution Description

Section 3 of NEDC-33075P, Revision 7 (Reference 1) describes in detail the DSS-CD methodology. In summary, DSS-CD is based on the approved Solution III, and it shares most of its features. There are only two major differences between Solution III and DSS-CD:

1. DSS-CD does not require the calculation of an amplitude setpoint to trigger scram actuation if the period-based algorithm (PBA) identifies an instability event. Instead, DSS-CD implements an amplitude discriminator that is [

   ] With DSS-CD implemented, the reactor will trip automatically if [

   ] Therefore, DSS-CD does not rely on generic correlations like DIVOM or cycle-specific calculations.

2. To prevent spurious scrams, DSS-CD [

] The CDA is relatively complex to cover all possibilities of combinations of failed and unresponsive OPRM cells, but under most conditions,[
]

Other features of the DSS-CD methodology include:

1. DSS-CD maintains the defense-in-depth algorithms that were approved for Solution III: the PBDA, the amplitude based algorithm (ABA), and the growth rate algorithm (GRA). The ABA and GRA remain unchanged from the previously approved solution and provide defense-in-depth in the unlikely event that the CDA fails to detect the instability due to unforeseen situations. The range of setpoint values is now provided in Table 3-4 of NEDC-33075P, Revision 7 (Reference 1).

2. PBDA was the primary algorithm in Solution III, and it is retained in DSS-CD with the defined parameter settings documented in Table 3-4 of Reference 1. PBDA will provide a scram if [
] as documented in Table 3-4 of Reference 1. PBDA thus provides defense-in-depth in case the confirmation density algorithm fails in an unexpected mode.

3. DSS-CD can be implemented as a software change using the existing GEH Nuclear Measurement Analysis and Control (NUMAC) hardware (Reference 9) currently used for Solution III. This review does not address implementation with non-GEH hardware.

4. In addition to the DSS-CD algorithm, NEDC-33075P (Reference 1) describes a backup stability protection (BSP) methodology. The BSP is intended to provide SLMCPR protection if the regular DSS-CD is declared inoperable. With BSP, the DSS-CD methodology attempts to incorporate the lessons learned from recent 10 CFR 50 Part 21 notifications, when the primary stability protection system is declared inoperable.

Figure 1 illustrates the operation of the main DSS-CD algorithm (CDA) and the defense-in-depth algorithms (PBDA, GRA, and ABA). The defense-in-depth algorithms would only be required in case the CDA failed for an unforeseen reason. They are armed when [
]

BSP is described in Section 7 of NEDC-33075P (Reference 1) and it consists of three different options: (a) “Manual BSP,” (b) “Automated BSP” (ABSP), and (c) “BSP Boundary.” All three BSP options define cycle-specific exclusion regions, which are defined in the core operating limits report (COLR). In the ABSP option, the scram is performed automatically by the DSS-CD hardware. In the manual BSP option, the scram is enforced administratively. The BSP Boundary option limits high power operation [ ] when DSS-CD is not operable to ensure [
]

The BSP methodology is an integral part of DSS-CD, which requires a non-manual backup option for operation in the MELLLA+ domain if the DSS-CD solution is declared inoperable. However the applicability of BSP is not limited only to DSS-CD. It may also be used in plants with other long term solutions (Reference 10) to replace the current interim corrective actions (ICAs). The main advantage of BSP over ICAs is that BSP requires plant- and cycle-specific stability exclusion regions; therefore, more stable plants have smaller exclusion regions and less stable plants have larger regions. ICAs are generic in nature and treat all plants by the same norm. They are based mostly on historical plant operating experience, which may or may not be applicable to new fuels and operating strategies that include high power densities with flat power distributions. By requiring plant- and cycle-specific exclusion region calculations, the BSP methodology guarantees that the stability regions are up to date for each particular core loading and operating strategy.

[

]

Figure 1. Illustration of Licensing Basis (CDA) and Defense-in-Depth Algorithms

The DSS-CD hardware design is unchanged from the Option III solution described in Reference 3, and it has not changed in Revision 7.

The basic input unit of the DSS-CD system is the OPRM cell. The OPRM cell consists of one to eight closely spaced LPRM detectors. The signals from the individual LPRM detectors in a cell are averaged to produce the OPRM cell signal. [ ] The cell signal is filtered to remove noise components with frequencies above the range of stability related power oscillations. This is accomplished by a second order Butterworth filter with cutoff frequency of 1.0 Hertz (Hz). This conditioned signal is filtered again using a second order Butterworth filter with a shorter cutoff frequency of 1/6 Hz (or an equivalent time constant of 0.95 seconds) to produce a time-averaged value. The conditioned and time-averaged signals are used by the four algorithms to detect reactor instabilities. Each of the four independent OPRM channels consists of many OPRM cells distributed throughout the core so that each channel provides monitoring of the entire core.

The DSS-CD solution includes four separate algorithms for detecting stability related oscillations: CDA, Period Based Detection Algorithm (PBDA), Amplitude Based Algorithm (ABA), and Growth Rate Algorithm (GRA). The PBDA, ABA, and GRA detection algorithms provide the protection basis for long term solution Option III (References 3 - 5). For long term solution Option III, only the PBDA is credited in the analysis, while ABA and GRA are defense-in-depth algorithms. PBDA, ABA, and GRA are retained in DSS-CD as defense-in-depth algorithms and are not part of the licensing basis for the DSS-CD solution, which is accomplished solely by the CDA. The CDA is designed to recognize an instability [ ]

The CDA capability of early detection and suppression of instability events is achieved by relying [ ] The CDA employs [ ] The CDA identifies a confirmation density (CD), [ ] A reactor trip is initiated when multiple channel trip signals are generated, consistent with the reactor protection system (RPS) logic design. [ ] DSS-CD eliminates the reliance on the PBDA amplitude setpoint, which is included in the licensing basis of Option III. The instability suppression by the DSS-CD for high growth instability events [ ] Because the solution does [ ]

Section 3.4.1 of NEDC-33075P, Revision 7 [ ] The NRC staff agrees that this process is significantly more conservative for detecting power oscillations.

3.2. Key Review Features

The primary focus of the NRC staff's review was to determine whether the DSS-CD modifications proposed in NEDC-33075P, Revision 7 (Reference 1) satisfy the minimum requirements for a long-term solution by providing compliance with GDC 10 and 12. DSS-CD provides compliance by detecting and suppressing oscillations.

3.2.1. Licensing Basis

The licensing basis for the DSS-CD approach is to [ ] Thus, the DSS-CD [ ] This solution guarantees compliance with the SAFDLs.

Because DSS-CD does [ ] GEH demonstrates compliance with the SAFDLs [ ]. NEDC-33075P, Revision 7 (Reference 1) documents [

] (see Table 4-2 of Reference 1). In addition, DSS-CD has been demonstrated to work successfully for real-plant data, including the Nine Mile Point 2 event. For all the analyzed transients, the final MCPR margin is significant due to [ ]

The NRC staff finds, based on engineering judgment, that it is reasonable to expect that the [ ] real plant data application in NEDC-33075P, Revision 7 (Reference 1) will bracket most future situations. The analyses [

] The analyses cover a wide range [ ] which is as large as should be expected. For all cases, the [

] (see Figures 4-17 and 4-18 of Reference 1 for an example).

3.2.2. Modifications to the Period Based Algorithm

[

]

3.2.3. Reload Analysis and Methodology Applicability Extension

The DSS-CD reload licensing methodologies are described in Section 6 of the subject TR (Reference 1). Table 6.1 documents [

]

For a new cycle in an already approved DSS-CD plant, [

]

Section 6 of NEDC-33075P (Reference 1) describes the procedure for [

]

The NRC staff finds this [ ] acceptable because it involves a plant- and cycle-specific calculation of [ ]

3.2.4. Backup Stability Protection

The example simulations in Section 4 of NEDC-33075P, Revision 7 (Reference 1) indicate that [ ] GEH has concluded and the NRC staff concurs, that [ ] Thus, a BSP is required in case DSS-CD is declared inoperable. The BSP concept, documented in Section 7 of NEDC-33075P, Revision 7 (Reference 1) is a technically acceptable solution to the backup issue.

As described in Section 7 of the subject TR (Reference 1), the BSP methodology defines cycle-specific exclusion regions, which are documented in the COLR. These regions are calculated with a licensed stability code (e.g., ODYSY (Reference 11)) with well-defined procedures (see Table 7-1 of NEDC-33075P, Revision 7 (Reference 1)). The exclusion region is similar to the Solution I-A regions, but uses different criteria. In general, the BSP regions should be smaller (i.e., less conservative) than the Solution I-A regions for the same reactor.

In essence, BSP regions are cycle-specific, best-estimate exclusion regions, while the Solution I-A regions are expected to be bounding (i.e., conservatively large) for most postulated situations. Using cycle-specific, best-estimate regions for BSP is justified because BSP is only a backup solution that should never be in effect, and if needed, will be used only for short periods of time (e.g., less than 120 days, per Technical Specifications (TSs)). The probability of an instability event in a particular plant under those circumstances is small. The probability of a non-best-estimate instability event during this short period is sufficiently small to justify the use of these regions.

The BSP methodology is composed of three elements: (a) manual, (b) automated (ABSP), and (c) BSP Boundary. The manual BSP methodology is intended only as a transition between DSS-CD and ABSP or BSP Boundary. Manual BSP will be used only for at most the first 12 hours after DSS-CD is declared inoperable. This is a standard TS requirement that accounts for the time needed to switch from DSS-CD to the ABSP protection, and it is technically acceptable.

With the ABSP option, a scram is automatically initiated if the reactor enters the exclusion region. With the BSP Boundary option, [ ] It is noted that [ ] Any instability that develops due to a slow rise in power level can be easily detected and suppressed by operator action.

Both the ABSP and the BSP Boundary rely [ ] As discussed above, these calculations are of a “best-estimate” nature [ ] It is unlikely, but not impossible, that an instability could be developed outside the calculated regions if, for example, unusual power distributions were present in the core (e.g., significant number of fuel failures leading to an unusual control rod pattern). However, the probability is very small that an unusual condition that leads to instability would be present in the core while the primary DSS-CD algorithm is inoperable. Therefore, the NRC staff concludes that the proposed BSP methodology is acceptable, and provides sufficient protection against SLMCPR violations commensurate with the probability of an instability event occurring in the short period of time that BSP would be active.

3.2.5. Technical Specification Requirements

The impact on TSs is documented in Section 8 of NEDC-33075P, Revision 7 (Reference 1). The TR appendix shows an example TS for a BWR/4. The proposed modifications are acceptable. In summary, they require DSS-CD to be operable, and they set operability and surveillance requirements consistent with other reactor protection systems. In case DSS-CD is declared inoperable, an immediate switch to manual BSP is required, and a switch to either ABSP or BSP Boundary is required within 12 hours. In case the ABSP is also declared inoperable, DSS-CD must be restored to full operation within 120 days. When a report is required by Condition I of Limiting Condition for Operation 3.3.1.1, "RPS Instrumentation," a report shall be submitted within 90 days of entering Condition I. The report shall outline the preplanned means to provide backup stability protection, the cause of the inoperability, and the plans and schedule for restoring the required instrumentation channels to operable status. The NRC staff agrees with the technical intent of the example TSs; however, the example TS are not written consistent with the improved Standard TS (STS) format. When referencing the subject TR in a licensing application, licensees should submit TS that are consistent with their current approved TS and the STS use and application section.

3.2.6. First Cycle Implementation

To prevent spurious scrams, the first cycle implementation of DSS-CD on a particular plant will allow the plant to disable DSS-CD during the first startup and shutdown maneuver. [ ]

During the first startup and shutdown, the alarm features of DSS-CD will be enabled; therefore sufficient protection will be provided during this short period of time. This is an acceptable approach.

Note that DSS-CD will be disabled only during startup and shutdown, but it will be enabled for the remainder of the cycle. Thus for an 18-month cycle, DSS-CD will be disabled only the first and last days of the cycle. DSS-CD will be enabled and ready to be armed and scram, if necessary, if a flow reduction occurs during the 18-month cycle.

3.3. DSS-CD Algorithm Setpoints and Adjustable Parameters

DSS-CD relies on the CDA. The CDA [ ], which are described in Table 1 below. The setpoint [ ] defined in Section 3.3.1.4 and Table 3.1 of the subject TR (Reference 1). [ ]

CDA is a relatively complex algorithm, and [ ] which are shown in Table 1 below. Based on the lessons learned from the Nine Mile Point 2 instability event and several years of in-plant operation experience, GEH has decided [ ] In Long Term Solution III, [ ] This is a good technical approach that [ ]

Both [ ] are defined in the subject TR (Reference 1). Deviation from the stated values or calculation formulas is not allowed without NRC review. To this end, the subject TR, when approved and implemented by a licensed nuclear power plant, must be referenced in the plant TS, so that these values become controlled and part of the licensing bases.

Even though CDA is the primary algorithm for the licensing basis, the BSP becomes the licensing basis for up to 120 days in the event of CDA failure. Plants may choose to implement one of two options: ABSP or BSP Boundary. Table 2 shown below documents the allowable setpoints for the ABSP option. Note that the BSP regions are plant- and cycle-specific and, as such, are defined in the COLR when this option is applicable. In addition, the ABSP option provides a rod block function that is not part of the licensing basis. Therefore, the rod block regions may be defined simply by plant procedures.

Both BSP Boundary and Manual BSP rely on operator actions that are defined by specific setpoint regions in the power-to-flow map. These regions are plant- and cycle-specific and must be specified in the COLR when this option is applicable.

Table 1. CDA Algorithm Setpoints and Parameters

Parameter Name	Definition	Parameter Type	Defined in
T_{min} (sec)	The Period Based Algorithm (PBA) oscillation period lower time limit for anticipated reactor instability. If the time between successive peaks or valleys is less than T_{min}, then it is not indicative of an anticipated reactor instability.	FIXED	Section 3.4.1.1. Same value as PBDA T_{min} in Table 3.4.
[		]	Section 3.4.1.1. Same value as PBDA [ ] in Table 3.4.
f_c (Hz)	Two-pole Butterworth filter cutoff frequency (Hz) for the conditioning filter to remove high frequency noise from the LPRM signals.	FIXED	Table 3.5.
ε (ms)	The PBA period tolerance. This parameter defines the limits within which successive oscillation periods may vary from the first (base) oscillation period in order to increment the number of confirmation counts. If the difference between an oscillation period and the base period is not within this tolerance, the number of confirmation counts is reset to zero.	FIXED	Table 3.5.
N_{Th}	The Confirmation Density Algorithm (CDA) successive confirmation count setpoint.	FIXED	Section 3.3.1.5 and Table 3.1.
P_b	OPRM Armed Region Lower Power Boundary (% Rated Power). The Simulated Thermal Power (STP) from the APRM channel is used to provide the power level.	FIXED	Section 4.5.
W_b	OPRM Armed Region Upper Flow Boundary (% Rated drive flow). The total recirculation flow (average of both loops) from the APRM channel is used to provide the recirculation drive flow.	FIXED	Section 4.5.
$LPRM_{min}$	Minimum number of operable LPRM input signals to an OPRM cell for the OPRM cell to be considered operable. Cell sensitivity generally increases with fewer operable LPRMs.	PLANT SPECIFIC	Section 3.3.1.3. Value is plant specific and will be defined in the plant specific application.
M_{AX}	An OPRM configuration constant representing maximum number of OPRM cells along an instability symmetry axis. It is used to calculate the number of unresponsive OPRM cells	PLANT SPECIFIC	Section 3.3.1.3. Value is plant specific and will be defined in the plant specific application.
[		]	Section 3.3.1.4 and Table 3.1.
[		]	Section 3.3.1.6 and Table 3.1.

Table 2. Automated Backup Stability Protection Setpoints

Parameter Name	Definition	Parameter Type	Defined in
m	Slope of the automatic Backup Stability Protection (BSP) APRM flow biased trip and rod block setpoint linear segments. [ ]	PLANT AND CYCLE SPECIFIC	Section 7.5
$P_{BSP\text{-}Trip}$[1]	Automatic BSP APRM flow biased trip setpoint power intercept (% Rated power). The Simulated Thermal Power from the APRM channel is used to provide the power level. [ ]	PLANT AND CYCLE SPECIFIC	COLR
$P_{BSP\text{-}RB}$[2]	Automatic BSP APRM flow biased rod block setpoint power intercept (% Rated power). The STP from the APRM channel is used to provide the power level. [ ]	PLANT AND CYCLE SPECIFIC	Plant procedures (rod block functions are not licensing basis)
$W_{BSP\text{-}Trip}$[1]	Automatic BSP APRM flow biased trip setpoint drive flow intercept (% Rated drive flow). The total recirculation flow (average of both loops) from the APRM channel is used to provide the recirculation drive flow. [ ]	PLANT AND CYCLE SPECIFIC	COLR
$W_{BSP\text{-}RB}$[2]	Automatic BSP APRM flow biased rod block setpoint drive flow intercept (% Rated drive flow). The total recirculation flow (average of both loops) from the APRM channel is used to provide the recirculation drive flow. [ ]	PLANT AND CYCLE SPECIFIC	Plant procedures (rod block functions are not licensing basis)

Notes: 1. Although this value is characterized by GEH as an ADJUSTABLE value, if the BSP trip function is credited as a licensing basis system, this value must be controlled consistent with the guidance provided by GEH.
2. Rod block limits are not licensing basis limits.

Table 3. Manual and Boundary Backup Stability Protection Setpoints

Parameter Name	Definition	Parameter Type	Defined in
GSF	The Generic Shape Function (GSF) defines the BSP exclusion regions based on the power and flow intercepts	FIXED	Section 7.2.1.1
MSF	The Modified Shape Function (MSF) defines a more accurate exclusion region based on cycle-specific DR calculations	PLANT AND CYCLE SPECIFIC	Section 7.2.1.2
Manual BSP Region I	Entry into Region I requires an immediate scram	PLANT AND CYCLE SPECIFIC	COLR
Manual BSP Region II	Inadvertent entry in Region II requires immediate exit. Intentional entry is permitted with stability control measured (See Section 7.2.3.2)	PLANT AND CYCLE SPECIFIC	COLR
BSP Boundary	Operation with higher power or lower flow than the BSP Boundary Line is not permitted in the MELLLA+ region	PLANT AND CYCLE SPECIFIC	COLR

3.4. Instrumentation and Control

The NRC staff's SE for NEDC-33075P, Revision 5 (Reference 2) included an evaluation of the implementation of DSS-CD with respect to instrumentation and control. The changes implemented in NEDC-33075P, Revision 7 do not relate to that evaluation and as such, do not impact the NRC staff's findings stated in section 3.6 of the SE in Reference 2. Those findings were not a part of the current review and remain in effect. The NRC staff's SE for NEDC-33075P, Revision 5 also contained two conditions and limitations for approval related to the instrumentation and control evaluation that remain in effect (conditions 8 and 9 of the NRC staff's SE for NEDC-33075P, Revision 5). For completeness, these conditions will be restated in section 5.0 of this SE as conditions 3 and 4.

3.5. NRC Calculations

The NRC staff has performed a number of TRACG calculations for the reviews of earlier versions of this TR. For these calculations, a 2RPT was simulated with the TRACG code resulting in unstable oscillations. These oscillations were then analyzed with the PERIOD code to simulate the behavior of the DSS-CD algorithm and to determine the time at which a scram would occur if the DSS-CD solution were implemented. The hot channel critical power ratio calculated by TRACG provides an indication of the effectiveness of the DSS-CD solution.

For all the cases analyzed by the NRC staff, the final MCPR margin at the moment of scram was larger than the initial MCPR. [ ] (for example, see Figure 7-10). Therefore, the NRC staff calculations confirm the TR conclusion that the DSS-CD solution is very effective in suppressing the unstable oscillations before fuel safety limits are compromised.

3.6. Revision 7 Updates

Page xiii of NEDC-33075P, Revision 7 (Reference 1) includes a comprehensive list of all 68 changes that were implemented in Revision 7 of the TR. Of these 68 changes, only 10 are non-trivial and they are summarized in Section 1.4 of the Reference 1. Of these 10 changes, the 2 most relevant updates are:

1. Upgrade to TRACG04/PANAC11 methodology.

2. A new methodology to allow for an increase in the amplitude setpoint discriminator from the already-approved [ ] if required due to large amplitude noise during normal operation.

Most other changes are editorial or clarifications. A list of the most significant changes follows:

1. Use of the TRACG04 version (References 12-14), including PRIME (Reference 15) fuel properties and gap conductance fuel input files.

2. Use of PANAC11 as three-dimensional neutron kinetics model (References 6 and 16-18).

3. Section 3.2 of the TR clarifies the reactor protection system trip logic. Figure 3-2 of the TR provides an example of the logic.

4. In Section 3.3.1 of the TR, a number of clarifications are provided for the methodology, including:

    a. the purpose of alarm settings,

    b. the logic if an OPRM channel is set to “INOP,”

    c. the single loop operation (SLO) amplitude discriminator setpoint determination,

    d. the description of the alarm settings, and

    e. the setpoint application process for higher-amplitude discriminator setpoints.

5. Section 3.3.1.6 of the TR contains an updated discussion of the two loop operation (TLO) amplitude discriminator setpoint determination based on recent plant data noise analyses.

6. Section 3.4.1 of the TR adds a description of the recommended selection of the defense-in-depth PBDA amplitude setpoints for higher CDA amplitude discriminator setpoints. Table 3.4 has been modified with the recommended defense-in-depth values.

7. Sections 4.4.1 and 4.4.2 of the TR update the TRACG cases and initial conditions to be run.

8. Section 4.7 was added to the TR, to cover CDA setpoints [ ] Table 4-17 provides a summary.

9. Section 5 has been shortened because the Code Scaling Applicability and Uncertainty (CSAU) section has been moved to the TR NEDE 33147P-A, Revision 4, "DSS-CD TRACG Application" (Reference 6).

10. Section 7.2 has been updated to allow the use of a modified shape function for BSP, consistent with other long term solution applications.

11. In Section 7.2.3.2, the BSP Control Entry Region definition criteria has been increased from decay ratio (DR)$\leq$0.6 to DR$\leq$0.8, and an Operator Awareness Region has been defined with 10 percent margin to the Control Entry Region.

As described in Section 2.3 of the TR, NEDC-33075P, Revision 7 (Reference 1) is supplemented by a separate TR on TRACG04 applicability, NEDE-33147P-A, Revision 4 (Reference 6). The CSAU section has been moved from the DSS-CD TR (Reference 1) to the approved DSS-CD TRACG Application TR (Reference 6). Since the information is provided, the new location of the CSAU is acceptable.

During implementation phases for DSS-CD, GEH [

] For these plants, [
] The approach taken in the subject TR revision is to allow for
[

]
This process is described in detail in Section 4.7 of the TR, along with an example application for [ ] The proposed approach is acceptable because:

]

[ ] in NEDC-33075P, Revision 7. These cases provide additional confidence that the DSS-CD solution provides sufficient margin to limits. These [
] Although this is recognized to be still true, [
] in Revision 7, which is acceptable.

The BSP solution has been updated to include a new modified shape function (MSF) that can replace the generic shape function (GSF). The MSF defines the exclusion region boundary for other long term solutions (specifically Solutions II, ID, and III) and operating plants are familiar with its use. MSF is smaller than the GSF, but it guarantees compliance by performing plant- and cycle-specific DR calculations. The process is described in Section 7 of the subject TR. Both approaches, GSF and MSF, are acceptable to define BSP exclusion regions because both approaches demonstrate very low likelihood of instabilities when operating outside the regions. The smaller MSF region is acceptable because it is confirmed by cycle-specific calculations.

Sections 3.3 and 3.4 of the subject TR describe the PBDA and CDA. No significant changes have been incorporated in this revision. The PBDA setpoint for the defense-in-depth function
[
] used for defense-in-depth. In this case, [
].

This modification is acceptable because [ ]

Tables 4-3 and 4-8 of the TR define the process that must be followed [ ] The methodology in Revision 7 of the TR includes the "20/50 bounding margin" that was approved in previous versions of the TR (Reference 2). Following a [ ] This approach remains acceptable.

Table 4-17 of the TR documents the process to evaluate amplitude setpoint S_{AD} values [ ] This methodology is a change in Revision 7 of the TR. Tables 4-15 and 4-16 document the required [ ] selected for a particular application. The use of Tables 4-15, 4-16, and 4-17 of the TR is acceptable for setpoint S_{AD} values [ ]

In Section 7.2.3.2 of Revision 7, GEH proposes to modify the criteria for point A' of the BSP Control Entry Region from DR<0.6 to DR<0.8. This loss of margin is compensated by [ ] This approach is acceptable because the [ ] in previous revisions of the TR. In addition, the Manual BSP entry regions are only used for defense-in-depth since the main backup solution is the ABSP, which automatically scrams the reactor.

Section 7.4 of the subject TR describes the ABSP function. In particular, Figures 7-9, 7-10, and 7-16 of the TR show that the ABSP function implements a preventive scram, which [ ] Thus, a setpoint calculation for ABSP is not required. Figure 2 and Figure 3 illustrate this point (these are Figures 7-9 and 7-10 of the subject TR). Figure 2 shows that BSP performs [ ] It is noteworthy that the CPR margin at the time of scram is even larger (i.e., more conservative) if the oscillations are allowed to develop because the core flow and power continue to be reduced following the pump trip and this may increase the available margin by a larger amount than the reduction caused by the incipient oscillations.

Section 8 of the TR has been updated with minor editorial changes to the proposed TS. The NRC staff finds these changes acceptable.

In summary, the NRC staff has reviewed the modifications to the design concept documented in NEDC-33075P, Revision 7 (Reference 1) and found them acceptable. The DSS-CD solution as described in Reference 1 complies with GDC 10 and 12 of 10 CFR Part 50, Appendix A, and enhances overall plant safety by providing a reliable, automatic oscillation detection and suppression function while avoiding unnecessary scrams.

[

]

Figure 2. Typical scram times for BSP and CDA functions

[

]

Figure 3. Typical CPR margins at scram time for BSP and CDA functions

4.0 RAI RESOLUTION

The NRC staff issued an RAI to GEH about a number of topics. Most of these requests were clarifications to the statements in the TR, or requests to define more specifically the methodology for future applications. GEH submitted detailed responses in Reference 19. The resolution of these responses is provided in this section. No open issues remain following this evaluation.

4.1. RAI 01 – Local Power Range Monitor Detector Modeling

The TRACG demonstration matrix relies on modeling the oscillation power range monitor (OPRM) response, which is obtained from the calculated local power range monitor (LPRM) time traces. Please provide a reference to how TRACG models the LPRM detectors and any available benchmarks.

The information was provided. LPRM signals in TRACG are calculated from the average nodal fission power of the eight surrounding kinetics nodes. The TRACG LPRM values have been qualified against data for the Peach Bottom turbine trip tests, LaSalle instability event, Leibstadt stability tests, and the Nine Mile Point 2 instability event in Reference 13.

4.2. RAI 02 – Requirement For Full Analysis Matrix

Section 4.7.2 of NEDC-33075P states that [

] The wording appears to be misleading because additional analyses are required if the applicability checklist is not satisfied. Please specify under which circumstances the full analysis matrix is required.

In the RAI response, GEH clarifies that additional analyses are required each time the applicability checklists in Tables 4-1 and 4-6 of NEDC-33075P, Revision 7 (Reference 1) are not satisfied. The response is consistent with the review of previous versions of the TR, and it is acceptable.

4.3. RAI 03 – Definition of RS Term

Please define the term “RS” and its units in the figure on page 4-27 labeled “OPRM Cell 121.”

In the RAI response, GEH clarifies that the RS signal is normalized and has no units. It represents the filtered OLPRM value divided by its running average. A short explanation about the meaning and units of RS will be added to the approved TR.

4.4. RAI 04 – Clarification of Data in Table 4-28

In the table on page 4-28, the fourth column is labeled [

] However, only one margin value is presented in the table, which appears to be the TLO margin. Please explain. Please specify whether [

] in the third column of this table.

In the RAI response, GEH provides additional data to demonstrate that the values in Table 4-28 are calculated correctly. The values represent either [ ] The values are [ ], which is applied at the next step of the process.

4.5. RAI 05 – Plant X Margins VS Matrix Evaluation

In the table on page 4-29, the fifth column is labeled [ ] Since NEDC-33075P is the DSS-CD LTR, this statement is somewhat confusing. Does this mean [ ]? Would a restriction on initial MCPR/operating limit MCPR (IMCPR/OLMCPR) be imposed if the "Plant X" margins were lower than the "Matrix" margins?

In the RAI response, GEH clarifies that the [ ] that the values in the table [ ] GEH also clarifies that if Plant X margins were lower than the Matrix, [ ] The [ ] Plant X may or may not have [ ] The NRC staff finds this approach] acceptable.

4.6. RAI 06 – Step 7 Clarification

Step 7 on page 4-29 is confusing. It refers to an [ ] It is not clear from the text in Step 7 how plant X satisfies this criterion. Do the criteria in Table 4-15 [ ]? Please explain Step 7 in more detail.

In the RAI response, GEH clarifies Step 7. The values provided as [ ]. Step 8 shows an example.

4.7. RAI 07 – Typographical Error

In Table 3-4, the period based detection algorithm setpoint (Sp) value in row 2, column 3 is marked as proprietary; however, on page 3-24, the same formula for Sp is not marked as proprietary. Please provide the correct proprietary marking. Additionally, for this Sp value in Table 3-4, the "max" function is missing the closing parenthesis.

In the RAI response, GEH clarifies that the Sp algorithm is indeed proprietary. The corrections will be included in the approved version of the TR.

5.0 LIMITATIONS AND CONDITIONS

The NRC staff's approval of NEDC-33075P, Revision 7 is subject to the following limitations and conditions:

1. The NRC staff previously reviewed and approved the implementation of DSS-CD using the approved GEH Option III hardware and software. The DSS-CD solution is not approved for use with non-GEH hardware. The hardware components required to

implement DSS-CD are expected to be those currently used for the approved Option III. If the DSS-CD hardware implementation deviates from the approved Option III solution, a hardware review by the NRC staff will be required. Implementations on other Option III platforms will require plant-specific reviews.

2. The CDA setpoint calculation formula and the adjustable parameters values are defined in NEDC-33075P, Revision 7 (Reference 1). Deviation from the stated values or calculation formulas is not allowed without NRC review. To this end, the subject TR, when approved and implemented by a licensed nuclear power plant, must be referenced in the plant TSs, so that these values become controlled and part of the licensing bases.

3. The NRC staff previously concluded that the plant-specific settings for eight of the FIXED parameters and three of the ADJUSTABLE parameters, as stated in section 3.6.3 of the NRC staff's SE for NEDC-33075P, Revision 5 (Reference 2), are licensing basis values. The process by which these values will be controlled must be addressed by licensees.

4. If plants other than Brunswick Steam Electric Plant, Units 1 and 2, use the DSS-CD trip function, those plant licensees must ensure the DSS-CD trip function is applicable in their plant licensing bases, including the optional BSP trip function, if it is to be installed.

6.0 CONCLUSION

Based on its review of the subject TR, as stated above, the NRC staff has reached the following conclusions:

1. NEDC-33075P, Revision 7, describes the DSS-CD methodology with a number of updates. The NRC staff concludes that DSS-CD, as updated in NEDC-33075P, Revision 7, is a technically acceptable methodology to detect and suppress oscillations should they occur and, thus, satisfies GDC 10 and GDC 12.

2. The existing Solution III is already approved for plant operation up to 20 percent EPU. DSS-CD is an extension of Solution III, where the need to determine the PBDA scram setpoint with a DIVOM correlation is eliminated by [

   ] Thus, DSS-CD is, in essence, [

   ] Therefore, DSS-CD is a technically acceptable methodology for any reactor operating up to and including EPU conditions.

3. The confirmation analyses documented in Section 4 of NEDC-33075P, Revision 7 (Reference 1), indicate that the DSS-CD methodology provides significant protection against MCPR criteria violations during anticipated instability events even under high-power-density conditions, including EPU and MELLLA+. Under all analyzed conditions, the loss of MCPR margin induced by the instability event is compensated by the gain in MCPR margin induced by the reduction in flow, so that the net MCPR margin is positive. Based on this analysis, DSS-CD is a technically acceptable methodology for any reactor operating up to and including MELLLA+ conditions.

4. Analyses documented in NEDC-33075P, Revision 7 (Reference 1), indicate that for reactors operating in the MELLLA+ domain: (a) instabilities are very likely following flow

reduction events; (b) for some plants these instabilities may develop in a time frame of a few seconds, so that manual operations to suppress them are not acceptable; and (c) the consequences of these instabilities can be serious. Therefore, plants operating in the MELLLA+ domain require a backup methodology that does not rely on manual operator actions in the event that DSS-CD is declared inoperable.

5. An acceptable BSP methodology is described in Section 7 of NEDC-33075P, Revision 7 (Reference 1), and it provides three different elements: Manual BSP (Section 7.2), BSP Boundary (Section 7.3), and ABSP (Section 7.4).

    a. The ABSP option and the BSP Boundary option are acceptable backup solutions for short periods of time when the licensed solution (e.g., DSS-CD) is declared inoperable. For BSP Boundary, this time is limited to 120 days. This time frame is consistent with Action 3.3.1.1-J.3 of the proposed TSs.

    b. The Manual BSP option without the BSP boundary is only acceptable for very short periods of time (up to 12 hours) while one of the other two BSP solutions is activated. This time frame is consistent with Action 3.3.1.1-I.2 of the proposed TSs.

6. Tables 6-1 and 6-2 of NEDC-33075P, Revision 7 (Reference 1) document a plant-specific applicability checklist, which contains specific criteria that must be reviewed and satisfied for each core reload. This methodology is a technically acceptable process for plant- and cycle-specific reviews of DSS-CD applicability.

7. For situations where the plant applicability checklist is not satisfied (e.g., introduction of a new fuel type) Tables 6-3 and 6-4 of NEDC-33075P, Revision 7 (Reference 1), describe the approved fuel transition scenarios when plant-specific review is not required.

8. Section 8 of NEDC-33075P, Revision 7 (Reference 1), provides a description of required changes to TSs, and an example is provided in Appendix A. The proposed TSs are an acceptable implementation of DSS-CD, except as noted in Section 3.2.5 above with regard to the format of the proposed TSs. When referencing the subject TR in a licensing application, licensees should submit TSs that are consistent with their current approved TSs and the improved STS use and application section.

9. Table 6-5 of NEDC-33075P, Revision 7 (Reference 1), describes the approved fuel transition scenarios, so a plant-specific submittal is not required.

10. Tables 4-15, 4-16, and 4-17, and Section 4.7 of NEDC-33075P, Revision 7 (Reference 1), provide an acceptable methodology to use plant-specific amplitude discriminator CDA setpoints (S_{AD}) for plants where [ ] The proposed approach is acceptable because: (1) [and (2) [ ]

11. Application of an alternative to the generic CDA setpoints defined in NEDC-33075P, Revision 7 (Reference 1) [ ] with respect to the susceptibility of a plant's intrinsic noise will require plant-specific review.

12. The full statistical application of the CSAU methodology (Reference 6) demonstrates that the [ ] methodology approved for DSS-CD applications is conservative and its use is acceptable.

13. The modification of the criteria for point A' of the BSP Control Entry Region from DR<0.6 to DR<0.8 is acceptable because [ ]

Based on this review and the conclusions stated above, subject to the limitations and conditions stated in Section 5.0 of this SE, NEDC-33075P, Revision 7, is approved for DSS-CD applications in General Electric (GE) BWR/3-6 product lines, with GE14 and earlier GE fuel designs, and for operating envelopes up to and including EPU and MELLLA+. For any other fuel design, the fuel transition process described in Table 6-5 is approved.

7.0 REFERENCES

1. TR NEDC-33075P, Revision 7, "General Electric Boiling Water Reactor Detect and Suppress Solution-Confirmation Density," dated June 2011. (ADAMS Package Accession No. ML111610593)

2. TR NEDC-33075P-A, Revision 6, "General Electric Boiling Water Reactor Detect and Suppress Solution-Confirmation Density," dated January 2008. (ADAMS Package Accession No. ML080310384)

3. TR NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," dated November 1995. (ADAMS Legacy Accession No. 9603130105)

4. TR NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," dated November 1995. (ADAMS Legacy Accession No. 9603130105)

5. TR NEDO-32465-A, "BWR Owners' Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," dated August 1996. (ADAMS Package Accession No. ML072260045)

6. TR NEDE-33147P-A, Revision 4, "DSS-CD TRACG Application," dated August 2013. (ADAMS Package Accession No. ML13224A319)

7. TR NEDO-32465 Supplement 1, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10 for Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," dated September 2011. (ADAMS Accession No. ML112550358)

8. Letter from Monticello Nuclear Generating Plant to NRC, L-MT-12-108, "Maximum Extended Load Line Limit Analysis Plus License Amendment Request – Request for Additional Information Responses for TRACE/TRACG Differences (TAC ME3145)," dated December 21, 2012. (ADAMS Accession No. ML13002A261)

9. TR NEDC-32410P-A, Supplement 1, “NUMAC-PRNM Retrofit Plus Option III Stability Trip Function,” dated November 1997. (ADAMS Legacy Package Accession No. 9806120229A)

10. BWROG-94078, “BWR Owner’s Group Guidelines for Stability Interim Corrective Action,” dated June 1994. (ADAMS Legacy Accession No. 9406150226)

11. TR NEDC-32992P-A, “ODYSY Application for Stability Licensing Calculations,” dated July 2001. (ADAMS Package Accession No. ML012610606)

12. TR NEDE-32176P, Revision 4, “TRACG Model Description,” dated January 2008. (ADAMS Package Accession No. ML080370259)

13. TR NEDE-32177P, Revision 3, “TRACG Qualification,” dated August 2007. (ADAMS Package Accession No. ML072480007)

14. TR NEDE-32906P-A, Revision 3, “TRACG Application for Anticipated Operational Occurrences (AOO) Transient Analyses,” dated April 2003. (ADAMS Package Accession No. ML062720163)

15. TR NEDC-33256P-A, Revision 1, “The PRIME Model for Analysis of Fuel Rod Thermal – Mechanical Performance Part 1,” Technical Bases, NEDC-33257P-A, Revision 1, “Part 2 –Qualification,” and NEDC-33258P-A, Revision1, “Part 3 - Application Methodology,” dated September 2010. (ADAMS Package Accession No. ML102600259)

16. TR NEDE-30130-P-A, “Steady State Nuclear Methods,” dated April 1985. (ADAMS Legacy Package Accession No. 8505090321)

17. TR NEDE-32906P, Supplement 3-A, Revision1, “Migration to TRACG04/PANAC11 from TRACG02/PANAC10 for TRACG AOO and ATWS Overpressure Transients,” dated April 2010. (ADAMS Package Accession No. ML110970401)

18. Letter from NRC to General Electric Nuclear Energy, “Amendment 26 to GE Licensing Topical Report NEDE-24011-P-A, “GESTAR II” Implementing Improved GE Steady-State Methods (TAC No. MA6481)”, FLN-1999-011, dated November 10, 1999. (ADAMS Package Accession No. ML993230387)

19. Letter from GEH to NRC, MFN 12-078, “Response to Request for Additional Information Re: GE-Hitachi Nuclear Energy Americas Topical Report (TR) NEDC-33075P, Revision 7 and NEDO-33075, Revision 7, “GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density” (TAC No. ME6577),” dated June 27, 2012. (ADAMS Package Accession No. ML121790572)

Attachment: Resolution of Comments Table (non-proprietary)

Principal Contributors: Tai Huang, SRXB/DSS
Jose March-Leuba, ORNL

Date: November 14, 2013

Comment Resolution Table for NEDE-33075P, Revision 7, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution-Confirmation Density"

#	Location In Draft SE	GEH Comment	NRC Staff Resolution
1	Section 1.0 Introduction Page 1 (lines 40-41), Page 2 (line 1)	GEH suggests the following changes: **A Final Safety Evaluation has been issued for NEDE-33147P, Revision 3 (Reference 6), while NEDO-32465 Supplement 1 (Reference 7),** ~~These additional~~ TR~~s are simultaneously~~ **is** currently under review by the NRC staff.	Replaced last sentence of paragraph with: "TR NEDO-32465, Supplement 1 is still under NRC staff review." Revised Reference 6 to reflect that final SE and "-A" version of NEDC-33147P have been issued.
2	Table 2 Page 14 (parameter name GSF & MSF)	Delete first two rows. Move these first two rows from Table 2 to Table 3.	Incorporated.
3	Table 2 Page 14 (parameter name m)	GEH suggests the following change: Slope of the automatic Backup Stability Protection (BSP) APRM flow biased trip and rod block setpoint linear segments. [[ ]]	Incorporated.
4	Table 2 Page 14 (parameter name P_{BSP-RB}^2)	GEH suggests the following change: Automatic BSP APRM flow biased rod block setpoint power intercept (% Rated power). The STP from the APRM channel is used to provide the power level. [[ ]]	Incorporated.

#	Location In Draft SE	GEH Comment	NRC Staff Resolution
5	Table 2 Page 14 (parameter name $W_{BSP-RB}{}^{2}$)	GEH suggests the following change: Automatic BSP APRM flow biased rod block setpoint drive flow intercept (% Rated drive flow). The total recirculation flow (average of both loops) from the APRM channel is used to provide the recirculation drive flow. [[ ]]	Incorporated.
6	Table 2 Page 14 (lines 3 & 5)	Please change "GE" to "GEH" in two locations.	Incorporated.
7	Table 3 Page 15 (Table 3)	Add first two rows from Table 2 (parameters GSF and MSF).	Incorporated.
8	Table 3 Page 15 (parameter name Manual BSP Region II)	GEH suggests the following change: Inadvertent entry in Region II requires immediate exit. Intentional entry is permitted with stability control measured (See Section 7.2.3.2 ~~of the Approved LTR~~)	Incorporated.
9	Section 3.6 Revision 7 Updates Page 17 (line 19)	GEH suggests the following changes: "… from decay ratio (DR)**≤**~~<~~0.6 to DR**≤**~~<~~0.8, and an Operator Awareness Region has been …."	Incorporated.
10	Section 3.6 Revision 7 Updates Page 17 (line 25)	GEH suggests the following addition: "…which has been ~~submitted~~ **reviewed and approved** separately to the …"	Sentence revised as follows: "The CSAU section has been moved from the DSS-CD TR (Reference 1) to the approved DSS-CD TRACG Application TR (Reference 6) ~~which has been submitted separately to the NRC for review~~."

#	Location In Draft SE	GEH Comment	NRC Staff Resolution
11	Section 3.6 Revision 7 Updates Page 17 (line 33)	GEH suggests the following change: [[ ]]	Incorporated.
12	Section 3.6 Revision 7 Updates Page 19 (line 8)	GEH suggests the following change: "…flow and power continue to be reduced following the pump trip and this **may** increase~~s~~ the available…"	Incorporated.
13	Section 6.0 Conclusion Page 24 (line 1)	GEH suggests the following change: "…reduction events; (b) **for some plants** these instabilities **may** develop in a time frame of…"	Incorporated.
14	Section 6.0 Conclusion Page 24 (line 8)	GEH suggests the following change: "…(Reference 1), and it provides three different ~~options~~ **elements**: Manual BSP…"	Incorporated.
15	Section 6.0 Conclusion Page 24 (lines 12-14)	GEH suggests the following clarification to Item 5.a: The ABSP option and the BSP Boundary option are acceptable backup solutions for short periods of time ~~(up to 120 days for BSP Boundary)~~ when the licensed solution (e.g., DSS-CD) is declared inoperable. **For the BSP Boundary, this time is limited to 120 days.** This time frame is consistent with Action 3.3.1.1-J.3 of the proposed TSs.	Incorporated.

#	Location In Draft SE	GEH Comment	NRC Staff Resolution
N/A	Section 6.0 Conclusion Item #7.	Additional change made by NRC staff.	Revised paragraph as follows: For situations where the plant applicability checklist is not satisfied (e.g., introduction of a new fuel type) Tables 6-3 and 6-4 of NEDC-33075P, Revision 7 (Reference 1), describe the approved fuel transition scenarios when plant-specific review is not required~~describe an acceptable procedure to extend the future applicability of DSS-CD~~.
16	Section 6.0 Conclusion Page 24 (lines 37-39)	GEH suggests the following change to Item 9: Table 6.5 of NEDC-33075P, Revision 7 (Reference 1), describes the **approved** fuel transition scenarios, **so** ~~which are subject to~~ a plant-specific ~~review for each application~~ **submittal is not required**.	Incorporated.
17	Section 6.0 Conclusion Page 25 (line 2)	GEH suggests the following change: [ ]	Incorporated.
18	Section 6.0 Conclusion Page 25 (lines 20-21)	GEH suggests the following addition: **For any other fuel design, the fuel transition process described in Table 6-5 is approved.**	Incorporated.

#	Location In Draft SE	GEH Comment	NRC Staff Resolution
19	Section 7.0 References Page 26 (lines 22-23)	GEH suggests the change to Reference 6: TR NEDE-33147P**-A**, Revision **4**~~3~~, "DSS-CD TRACG Application," dated **August 2013.**~~January 2011.~~ ~~(ADAMS Package Accession No. ML110270071)~~	Reference 6 was revised as follows: TR NEDE-33147P-A, Revision 4, "DSS-CD TRACG Application," dated August 2013. (ADAMS Package Accession No. ML13224A319)
20	Appendix A Introduction Page A-1 (lines 32-33)	"The NRC staff ~~is currently also reviewing~~ **has reviewed and approved** the TRACG04 code for DSS-CD application,	Incorporated.
21	Appendix A References Page A-3 (lines 39-40)	GEH suggests the change to Reference 2: TR NEDE-33147P**-A**, Revision **4**~~3~~, "DSS-CD TRACG Application," dated **August 2013.**~~January 2011.~~ ~~(ADAMS Package Accession No. ML110270071)~~	Reference 2 was revised as follows: TR NEDE-33147P-A, Revision 4, "DSS-CD TRACG Application," dated August 2013. (ADAMS Package Accession No. ML13224A319)
22	Appendix A	Note, consistent with the Technical Evaluation which was included in the SE for Revision 5 of NEDC-33075P, Appendix A is proprietary in its entirety.	Noted.
23	Entire document	Some of the information provided is considered to be GEH proprietary information. See the attached markup with dotted underline within double square brackets. [[This sentence is an example.{3}]]	Noted. NRC staff marked the proprietary content with bold text within single brackets. [**Example.**]

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EXECUTIVE SUMMARY

Under certain conditions, boiling water reactors (BWRs) may be susceptible to coupled neutronic/thermal-hydraulic instabilities. These instabilities are characterized by periodic power and flow oscillations. If these oscillations become large enough, and the associated density waves contain a sufficiently high void fraction, the fuel cladding integrity safety limit could be challenged.

Several different stability long-term solution (LTS) options have been developed for BWRs. Certain solutions depend upon automatic reactor instability detection and suppression to show compliance with licensing requirements. The Detect and Suppress Solution – Confirmation Density (DSS-CD) consists of hardware and software for the automatic detection and suppression of stability related power oscillations and represents an evolutionary step from the stability LTS Option III.

DSS-CD introduces an enhanced detection algorithm, the Confirmation Density Algorithm (CDA), which reliably detects the inception of power oscillations and generates an early power suppression trip signal prior to any significant oscillation amplitude growth and Minimum Critical Power Ratio (MCPR) degradation. This report provides a generic licensing basis for General Electric (GE) BWR/3-6 product lines, GE14 and earlier GE fuel designs and operating envelopes up to and including Extended Power Uprate (EPU) and Maximum Extended Load Line Limit Analysis Plus (MELLLA+). A standard procedure is identified for plant-specific confirmations of reload designs and other design changes that may affect the DSS-CD generic licensing basis.

REVISIONS

Revision 1:

1. Editorial clarifications and corrections.
2. Updated acknowledgement list.
3. Expanded proprietary marking to include GE proprietary processes.

Revision 2:

1. Minor editorial changes.
2. Correct channel trip designation in Section 3.2 for consistency with Figure 3-1.
3. Clarify in Sections 3.5 and 4.5 the MCPR monitoring threshold application to define the Armed Region boundary.
4. Revise "filter corner frequency" to "filter cutoff frequency" throughout the report for consistency.
5. Lower T_{min} value to bound expected period range for MELLLA+ operation.
6. Adjust f_c permissible range consistent with the revised T_{min} value.
7. Identify OPRM cell and channel responsiveness requirements, and clarify relationship to confirmation density setpoint.
8. Change the initial setting for the Period Based Algorithm (PBA) adjustable parameters consistent with plant operating experience.

Revision 3:

1. Minor editorial changes.
2. Clarify terminology use of RPS channel, OPRM channel and OPRM cell.
3. Change DSS-CD system operability requirement in Section 3.5.
4. Change unresponsive OPRM channel to inoperable (INOP) channel status.
5. Clarify that the selection of DSS-CD alarm setpoint is optional.
6. Clarify Manual BSP Region generation cycle exposure requirements, application procedure, and BSP Boundary feature.
7. Define HFCL for MELLLA+ and clarify use for MELLLA+ applications.
8. Identify BSP options

9. Add section of example Technical Specification.
10. Simplify MCPR margin applicability envelope definition.
11. Clarify Armed Region Boundary flow dependence.
12. Clarify that TRACG is not used to establish the SLMCPR.
13. Specify PBA cutoff frequency and period tolerance values.
14. Eliminate PBA calibration requirement.
15. Revise PBDA confirmation count setpoint value.
16. Specify TRACG fuel transition cases for expanding DSS-CD applicability envelope.

Revision 4:

1. Minor editorial changes.
2. Add to CDA an OPRM cell signal amplitude discriminator.
3. Add explicit TRACG OPRM cell modeling and apply the detection algorithm to OPRM cell signals instead of hot channel signals.
4. Address single loop operation.
5. Add Figure 3-1 to illustrate the DSS-CD detection algorithms time of trip for a growing oscillation.
6. Add basis for the selected OPRM signal averaging cutoff frequency value.
7. Specify a single period tolerance value in Table 3-5.
8. Correct C1AX entry in Table 5-3.
9. Clarify feedwater temperature considerations for Manual BSP Region generation.
10. Add optional exposure dependent BSP regions and boundary.
11. Correct Figures 7-2 and 7-4.
12. Revise the proposed requirement and purpose of TS Required Action I.3 to require NRC acceptance of corrective action plan and schedule.

Revision 5:

1. Minor editorial changes.
2. Clarify on-line implementation.
3. Correct BSP Boundary calculation procedure for xenon concentration and feedwater temperature in Table 7-2.

4. Update Tables 4-4, 4-5, 4-9 and 4-10, Figures 4-1 through 4-27 and 4-32 through 4-45, and the bounding CSAU oscillation component relative uncertainty to account for a void reactivity coefficient correction and the use of a transient CPR model in TRACG.
5. Clarify potential susceptibility to spurious scrams for plants exhibiting high noise level during stable operation.
6. Address partial flow reduction events.
7. Update Table 8-1, Technical Specifications, and associated Bases.

Revision 6:

(Note: The revision bars provided in Appendixes A and B do not reflect changes regarding Revision 6 of this LTR. The revision bars provided in Appendixes A and B indicate changes relative to the TS and Bases proposed in Reference 13 for BWR/4 Standard Technical Specifications.)

1. Added statement to Section 3.3.1.9 that each plant-specific application will address the margins to the SLMCPR and the margins presented in the DSS-CD LTR consistent with RAI 6 of MFN 06-105 [Reference 16].
2. Revised Section 4.4.2 and Figure 4-45 to reflect the correct timing for the SLO event. The NRC was informed of the required changes in conference call dated June 11, 2007 and agreed the changes should be incorporated in the 'A' version of the LTR.
3. Created 'A' version by adding the NRC Final Safety Evaluation [Reference 18] and GEH's responses to the NRC's requests for additional information (RAI) [References 14, 15, 16, and 17].
4. Deleted acknowledgement page.
5. Updated Generic Licensing Basis RAI 2 and BSEP Methodology RAI 6 of MFN 04-001 [Reference 14] consistent with commitments made in RAIs 8 and 11 of MFN 05-148 [Reference 15]. Note revision bars are not shown for the revisions to the RAIs because the RAIs were not part of Revision 5.
6. Added 'RAI' in the list of abbreviations.

Revision 7:

1. Minor editorial changes.
2. Updated cover page to reflect current revision.
3. Updated Proprietary Information notice.
4. Updated Affidavit.

5. Updated Acronyms and Abbreviations List.
6. Use of the TRACG04 version [References 8, 9, and 19], including PRIME [Reference 20] fuel properties and gap conductance fuel input files.
7. Use of the PANAC11 as three-dimensional neutron kinetics model [References 12, 19, 21, and 22].
8. Section 1.1: Added a statement about application of DSS-CD to new fuel designs.
9. Sections 1.4 and 2.3 were added to provide summary and introduction of key changes included in Revision 7 and to specify the purpose of Revision 7 submittal and review.
10. Section 3.2: Clarified RPS trip logic and updated corresponding Figure 3-2.
11. Section 3.3.1.3: Clarified purpose of alarm settings.
12. Section 3.3.1.4: Clarified logic if an OPRM channel is set to INOP.
13. Section 3.3.1.6: Updated the discussion of the TLO amplitude discriminator setpoint determination based on recent plant data noise analyses.
14. Section 3.3.1.7: Clarified the discussion of the SLO amplitude discriminator setpoint determination.
15. Section 3.3.1.8: Clarified the description of the alarms setpoint settings.
16. Section 3.31.9: Clarified the setpoint application process for higher amplitude discriminator setpoints.
17. Section 3.4.1: Added the description of the recommended selection of the DID PBDA amplitude setpoints for higher CDA amplitude discriminator setpoints.
18. Table 3-1: Updated for alarm settings and higher CDA amplitude discriminator setpoints.
19. Table 3-2: Fixed typos about the number of LPRM for OPRM cell.
20. Table 3-4: Updated recommended DID values and clarified their selection.
21. Section 4.3: Added reference to MCPR margins for higher CDA amplitude discriminator setpoints.
22. Section 4.4.1: Added discussion for the [[ ]] to the event matrix.
23. Section 4.4.1: [[ ]]
24. Section 4.4.1: Updated case name description for TRACG event matrix.
25. Section 4.4.1.1: Updated to reflect content that was moved from Revision 6 to NEDE-33147P Revision 3 (TRACG04 DSS-CD LTR). Updated figure numbering.
26. Section 4.4.1.2: Updated discussion and reference to NEDE-33147P Revision 3 (TRACG04

DSS-CD LTR) for CSAU and full core individual bundle model.

27. Section 4.4.2: [[ ]] to the event matrix and clarified Table 4-11 discussion.
28. Added Sections 4.7, 4.7.1, 4.7.2, and 4.7.3 to describe the licensing basis and the DSS-CD application process for higher CDA amplitude discriminator setpoints.
29. Table 4-2: Updated case name and added a case to the matrix.
30. Table 4-3: Added a reference for the application of the uncertainty.
31. Table 4-4: Updated cases and values based on TRACG04/PANAC11 results.
32. Table 4-5: Updated cases and values based on TRACG04/PANAC11 results.
33. Table 4-7: Updated case name and added a case to the matrix.
34. Table 4-8: Added a reference for the application of the uncertainty.
35. Table 4-9: Updated cases and values based on TRACG04/PANAC11 results.
36. Table 4-10: Updated cases and values based on TRACG04/PANAC11 results.
37. Table 4-11: Updated cases and values based on TRACG04/PANAC11 results.
38. Added Table 4-13, Table 4-14, Table 4-15 and Table 4-16 MCPR margins for higher CDA amplitude discriminator setpoints.
39. Added Table 4-17 to provide the process summary of the DSS-CD application process for higher CDA amplitude discriminator setpoints.
40. Updated Figures 4-1 through 4-6 to show TRACG04/PANAC11 results.
41. Deleted Figures 4-7 through 4-27 because these cases have been moved to NEDE-33147P Revision 3 (TRACG04 DSS-CD LTR).
42. Renumbered Figures 4-28 through 4-33 into Figures 4-7 through 4-12. Figure 4-29 (renumbered to Figure 4-8) was also updated and renamed to reflect full core individual bundle model.
43. Deleted Figures 4-34 through 4-38 because these cases are no longer applicable.
44. Renumbered and updated to show TRACG04/PANAC11 results Figures 4-39 through 4-44 into Figures 4-13 through 4-18.
45. Renumbered Figures 4-45 through 4-46 into Figures 4-19 through 4-20.
46. Sections 5.1, 5.1.1, and 5.2 significantly shortened because the TRACG application, qualification, and CSAU have been moved to NEDE-33147P Revision 3 (TRACG04 DSS-CD LTR).
47. Sections 5.1.2, 5.1.3, 5.1.4 deleted because the TRACG application, qualification, and CSAU have been moved to NEDE-33147P Revision 3 (TRACG04 DSS-CD LTR).

48. Section 5.4.1: Updated to add the CDA and the alarm amplitude discriminator settings description.
49. Tables 5-1 through 5-4 deleted because the TRACG application, qualification, and CSAU have been moved to NEDE-33147P Revision 3 (TRACG04 DSS-CD LTR).
50. Renumbered Tables 5-5 through 5-6 into Tables 5-1 through 5-2.
51. Section 6.1: Added reference for plant-specific applications with higher CDA amplitude discriminator setpoints; added statement to clarify plant-specific DSS-CD applications for new fuel designs.
52. Tables 6-1 and 6-2: Updated MCPR margin criteria and added a note to provide reference for application with higher CDA amplitude discriminator setpoints.
53. Tables 6-3 and 6-4: Updated for application with higher CDA amplitude discriminator setpoints.
54. Sections 7.2 and 7.2.2: Updated content to refer to Boundary Shape Function because the Modified Shape Function option was added.
55. Section 7.2.1: Added Modified Shape Function option.
56. Section 7.2.3.2: Updated discussion to describe the basis for the controlled entry region determination.
57. Sections 7.3 and 7.3.1: Updated discussion to support application of BSP boundary in MELLLA+ domain only.
58. Section 7.4.1: Clarified setpoint purpose of ABSP and rod block functions;
59. Section 7.5.2: Clarified the connection between BSP Option 1 and Option 2 in relation to the TS actions.
60. Added Section 7.5.4 to specify the ABSP setpoint implementation and basis for ABSP setpoints determination.
61. Updated Figures 7-2, 7-4, 7-5, 7-11 and 7-13 including cosmetic changes to clean up the plots.
62. Updated Figure 7-3 to reflect updated BSP criteria.
63. Updated Figures 7-6, 7-7, and 7-8 to reflect updated BSP Boundary implementation.
64. Added Figures7-14 and 7-15 to support discussion on BSP Boundary implementation.
65. Added Figure 7-16 to support discussion on improved ABSP Setpoint implementation.
66. Section 8: Updated Standard Technical Specification (TS) reference and clarified how TS changes are implemented fords-CD.to include
67. Section 9: Updated References 4, 6, 7, 8, and 9.

68. Section 9: Added References 19, 20, 21, 22, 23, 24, 25, and 26.

Revision 8

1. Created '-A' version by adding the NRC's Final Safety Evaluation (Reference 28) and GEH's responses to the NRC's Requests for Additional Information (RAIs) (Reference 27).
2. Marked the formula for S_p on page 3-24 in Section 3.4.1 as proprietary consistent with the response to RAI 07 in GEH's letter, MFN 12-078, dated June 27, 2012 (Reference 27).
3. Corrected typographical error in Table 3-4 consistent with the response to RAI 07 in GEH's letter, MFN 12-078, dated June 27, 2012 (Reference 27).
4. Added a note below the figure on page 4-27 in Section 4.7.3 consistent with the response to RAI 03 in GEH's letter, MFN 12-078, dated June 27, 2012 (Reference 27).
5. Added References 27 and 28.

ACRONYMS AND ABBREVIATIONS

Term	Definition
ABA	Amplitude Based Algorithm
ABSP	Automated BSP
ABWR	Advanced Boiling Water Reactor
AD_j	Amplitude Discriminator State
AGE	Approved GEH/GNF
ANGE	Approved Non-GEH/GNF
AOO	Anticipated Operational Occurrence
APRM	Average Power Range Monitor
ATWS	Anticipated Transient Without Scram
A_n	Averaged OPRM cell signal
BB	Boiling Boundary
BSF	Boundary Shape Function
BSP	Backup Stability Protection
BT	Boiling Transition
BWR	Boiling Water Reactor
CD	Confirmation Density
CD_j	j^{th} OPRM Channel Confirmation Density
CDA	Confirmation Density Algorithm
CFR	Code of Federal Regulations
CHAN	Fuel Channel
COLR	Core Operating Limits Report
CPR	Critical Power Ratio
CSAU	Code Scaling, Applicability and Uncertainty
C_n	Normalized OPRM cell signal
ΔCPR	Delta CPR
DIVOM	Delta over Initial MCPR Versus Oscillation Magnitude
DR	Decay Ratio
DSS-CD	Detect and Suppress Solution – Confirmation Density
ΔT_{FW}	Delta Feedwater Temperature

Term	Definition
E	Axial loss of PBA efficiency
ε	Period Tolerance
ε_{Input}	PBA Period Tolerance Selection
EPU	Extended Power Uprate
ER	Exclusion Region
f_c	Conditioning Filter Cutoff Frequency
FCL	Flow Control Line
FCV	Flow Control Valve
FTTC	Fuel Thermal Time Constant
F_{CD}^{Max}	Maximum response fraction ignoring axial PBA inefficiencies
GDC	General Design Criteria
GE	General Electric
GEH	GE-Hitachi Nuclear Energy Americas, LLC
GESTAR	General Electric Standard Application for Reload Fuel
GNF	Global Nuclear Fuel
GRA	Growth Rate Algorithm
GR_3	GRA Maximum Allowable Growth Rate
GSF	Generic Shape Function
HFCL	High Flow Control Line
ICA	Interim Corrective Action
ICPR	Initial Critical Power Ratio
IMCPR	Initial Minimum Critical Power Ratio
$IMCPR_{SLO}$	IMCPR for SLO condition
$IMCPR_{TLO}$	IMCPR for TLO condition
KKL	Kernkraftwerk Leibstadt
LTR	Licensing Topical Report
LTS	Long-Term Solution
LPRM	Local Power Range Monitor
LUA	Lead Use Assembly
MCPR	Minimum Critical Power Ratio

Term	Definition
MELLLA+, M+	Maximum Extended Load Line Limit Analysis Plus
M^{j}_{OP}	Number of Operable OPRM cells for j^{th} OPRM Channel
M^{j}_{RS}	Number of Responsive OPRM cells for j^{th} OPRM Channel
M^{j}_{AX}	Largest Number of OPRM cells Aligned Along a Regional Mode Instability Axis of Symmetry
M^{j}_{CD}	Number of OPRM cells at or above N_{Th} for j^{th} OPRM channel
M^{j}_{DL}	Number of Operable OPRM cells with Exclusive Input from D Level LPRMs
MG	Motor Generator
MOC	Middle of Cycle
MSF	Modified Shape Function
NA	Not Applicable
N_{Al}	Successive Confirmation Alarm Setpoint
NCL	Natural Circulation Line
N_i	Successive Confirmation Count of the i^{th} OPRM cell
N_P	PBDA Successive Period Confirmation Setpoint
NMS	Neutron Monitoring System
NRC	Nuclear Regulatory Commission
N_{Th}	Successive Confirmation Count Threshold
ODYSY	GEH Best-Estimate Frequency Domain Stability Code
OLMCPR	Operating Limit MCPR
$OLMCPR_{Rated}$	Rated power OLMCPR
$OLMCPR_{SLO}$	Off-rated OLMCPR for SLO event simulation
OLTP	Original Licensed Thermal Power
OPRM	Oscillation Power Range Monitor
Option II	Stability Detect and Suppress LTS for BWR/2
Option III	Stability OPRM-Based Detect and Suppress LTS, Relying on the PBDA, ABA, and GRA for Detection
PANACEA	GE BWR Core Simulator
PANAC11	PANACEA, GEH BWR Core Simulator
PBA	Period Based Algorithm

Term	Definition
PBDA	Period Based Detection Algorithm
PFR	Partial Flow Reduction
P_i^j	Last recorded peak of the normalized signal of the ith OPRM cell for the jth OPRM channel
PHE	Peak Hot Excess
PRNM	Power Range Neutron Monitor
P_1	GRA First Cycle Peak
RAI	NRC Request for Additional Information
RPS	Reactor Protection System
RPT	Recirculation Pump Trip
SAR	Safety Analysis Report
SCC	Successive Confirmation Count
SLMCPR	Safety Limit MCPR
SLO	Single Loop Operation
S_{AA}	Amplitude Alarm Setpoint
S_{AD}	Amplitude Discriminator Setpoint
S_{CD}^{Max}	Allowable CD setpoint upper bound
S_{max}	ABA Amplitude Trip Setpoint
S_n	Filtered OPRM cell signal
S_P	PBDA Amplitude Setpoint
SRLR	Supplemental Reload Licensing Report
S_{Th}^i	OPRM Instability Threshold Flag of ith OPRM cell
S_{CD}^j	jth OPRM Channel CD setpoint
S_1, S_2	ABA and GRA Amplitude Threshold Setpoints
S_3	GRA Trip Setpoint
THI	Thermal-Hydraulic Instability
TLO	Two Loop Operation
TRACG	Transient Reactor Analysis Code (GEH proprietary version)
T_{FW}	Feedwater temperature
T_{max}	PBA Time Period Upper Limit

Term	Definition
T_{min}	PBA Time Period Lower Limit
T_1, T_2	ABA and GRA Time Windows
UGE	Unapproved GEH/GNF
UNGE	Unapproved non-GEH/GNF
1-D	One-Dimensional
1RPT	One Recirculation Pump Trip
2oo4	Two-out-of-Four
2RPT	Two Recirculation Pumps Trip
3-D	Three-Dimensional

1.0 INTRODUCTION

1.1 BACKGROUND

Under certain conditions, boiling water reactors (BWRs) may be susceptible to coupled neutronic/thermal-hydraulic instabilities. These instabilities are characterized by periodic power and flow oscillations and are the result of density waves (i.e., regions of highly voided coolant periodically sweeping through the core). If the flow and power oscillations become large enough, and the density waves contain a sufficiently high void fraction, the fuel cladding integrity safety limit could be challenged.

The Detect and Suppress Solution – Confirmation Density (DSS-CD) solution consists of hardware and software that provide for reliable, automatic detection and suppression of stability related power oscillations. It is designed to identify the power oscillation upon inception and initiate control rod insertion to terminate the oscillations prior to any significant amplitude growth. The combination of hardware, software, and system setpoints provides protection against violation of the Safety Limit Minimum Critical Power Ratio (SLMCPR) for anticipated oscillations. Thus, compliance with General Design Criteria (GDC) 10 and 12 of 10 CFR 50, Appendix A is accomplished via an automatic action.

The DSS-CD is based on the same hardware design as Option III, which is described in References 1 through 3. However, it introduces an enhanced detection algorithm that detects the inception of power oscillations and generates an early power suppression trip signal based on successive period confirmation recognition and an amplitude component. The DSS-CD is designed to provide adequate automatic SLMCPR protection for anticipated reactor instability events. The existing Option III algorithms are retained (with generic setpoints) to provide defense-in-depth protection for unanticipated reactor instability events.

This report provides a generic licensing basis for DSS-CD applications to General Electric (GE) BWR/3-6 product lines, GE14 and earlier GE fuel designs and operating envelopes up to and including Extended Power Uprate (EPU) and Maximum Extended Load Line Limit Analysis Plus (MELLLA+ or M+). Section 6.0 of this report specifies the process to extend the applicability of DSS-CD to new fuels such as the GNF2 fuel design. Table 6-5 identifies various fuel transitions and the required TRACG cases required for the different fuel transitions.

Specific hardware/software designs are not addressed in this report and, if necessary, will be submitted separately for Nuclear Regulatory Commission (NRC) approval.

1.2 PURPOSE

This report provides the licensing basis and methodology to demonstrate the adequacy of the DSS-CD solution. Section 2.0 describes the solution design philosophy, including the licensing and defense-in-depth protection approach. Section 3.0 provides a detailed description of the key solution elements, including the licensing and defense-in-depth oscillation detection algorithms. Section 4.0 describes the solution's licensing basis. Section 5.0 describes the analytical and plant data qualifications of the solution detection algorithms. Section 6.0 describes the plant-specific confirmation process. Section 7.0 describes the Backup Stability Protection (BSP) feature to be employed in the unlikely event the DSS-CD licensing basis algorithm cannot be demonstrated to provide its intended SLMCPR protection. Section 8.0 discusses the effect on Technical Specifications and Bases for implementation of DSS-CD.

1.3 OVERVIEW

The licensing basis described in this report demonstrates on a generic basis that the DSS-CD features reliably detect and suppress anticipated stability related power oscillations. This provides a high degree of confidence that the SLMCPR is not violated, thus satisfying the requirements of GDC 10 and 12. The detection algorithm used for this purpose is termed the Confirmation Density Algorithm (CDA). The CDA monitors closely spaced groups of Local Power Range Monitor (LPRM) detectors to detect periodic behavior typical of reactor instability events. The CDA initiates a trip signal upon confirmation that an instability signal signature exists for a specified minimum number of LPRM groups.

The DSS-CD licensing basis consists of two major components:

a. An efficient oscillation detection algorithm, the CDA, providing an early trip signal following instability inception prior to any significant oscillation amplitude growth and Minimum Critical Power Ratio (MCPR) degradation, and

b. A set of integrated Transient Reactor Analysis Code (TRACG) event simulations for reasonably limiting anticipated events that confirm the limited effect on the MCPR performance within the stated applicability range.

To provide defense in depth, the DSS-CD solution includes additional detection algorithms that are not credited in the licensing basis but provide additional protection against unanticipated oscillations. The DSS-CD defense-in-depth detection algorithms are:

a. Period Based Detection Algorithm (PBDA),

b. Amplitude Based Algorithm (ABA), and

c. Growth Rate Algorithm (GRA).

The PBDA provides the licensing basis protection and the ABA and GRA provide the defense-in-depth protection for long-term solution (LTS) Option III (Reference 3). These algorithms are capable of initiating a trip signal to limit the size of an oscillation. Because these detection algorithms are not part of the DSS-CD licensing basis, no Technical Specification actions are required if any of these defense-in-depth algorithms are not operable.

This report also provides a description of BSP approaches that may be used when the DSS-CD licensing basis algorithm cannot be demonstrated to provide its intended SLMCPR protection.

1.4 REVISION 7 KEY CHANGES AND PURPOSE

The following are the main improvements included in this revision:

1. TRACG04 replaces TRACG02 as the BWR event simulation model (References 8, 9, and 19). The TRACG04 model includes PRIME (Reference 20) fuel properties and gap conductance fuel input files. The TRACG implementation of the PRIME fuel conductivity (approved in Reference 21) is used and the PRIME gap conductance files are attached.
2. PANAC11 replaces PANAC10 as the three three-dimensional (3-D) neutron kinetics model (References 12, 19, 21, and 22).
3. Removal of the Code Scaling, Applicability and Uncertainty (CSAU) sections and TRACG case duplications that are covered in Revision 3 of the TRACG04 DSS-CD Licensing Topical Report (LTR) (Reference 19).

4. MCPR margins are recalculated for the entire case event matrix using TRACG04/PANAC11.
5. TRACG MCPR Margin tables are expanded to cover for higher than [[ ]] amplitude discriminator setpoints and include tables of Operating Limit MCPRs (OLMCPRs) [[ ]] A more detailed description of the implementation of higher amplitude discriminator setpoints and of plant-specific DSS-CD applications is also provided.
6. A complete set of transient cases for the BWR/3-5 TRACG event matrix is provided as well as [[ ]] tables of OLMCPRs [[ ]]
7. Improvements and simplification of the preventive scram function of the Automated Backup Stability Protection (ABSP) setpoints.
8. The application of BSP Boundary is limited to MELLLA+ region.
9. The Manual BSP Region II (Controlled Entry Region) is based on core Decay Ratio (DR) equal to 0.8 criterion.
10. The Modified Shape Function (MSF) is added as an option for the determination of the BSP region boundaries.

The changes introduced in this report represent an addition to the existing licensing basis of the DSS-CD solution. In fact, there are no changes made to the current solution or the DSS-CD algorithms. Therefore, the improvements included in this report are to address certain aspects of the implementation of the DSS-CD solution arose on actual DSS-CD applications. This report represents an incremental extension of the DSS-CD licensing basis rather than a brand new licensing basis altogether.

GE-Hitachi Nuclear Energy Americas, LLC (GEH) requests an incremental review and approval of the improvements to the licensing basis for DSS-CD applications included in Revision 7 of this report and of the changes implemented from the approved Revision 6 (NEDC-33075P-A R6). This incremental review and approval of the improvements and changes included in this report is requested for DSS-CD applications to GE BWR/3-6 product lines, GE14 and earlier GE fuel designs and operating envelopes up to and including EPU and MELLLA+. In addition the approval of the improvements and changes included in this report is requested for DSS-CD applications extended to any new fuel designs (e.g., GNF2 fuel design) per the process described in Section 6.0 of this report and in Reference 23.

2.0 SOLUTION DESIGN PHILOSOPHY

2.1 DESIGN APPROACH

The design philosophy used in the development of the DSS-CD hardware/software and licensing basis is discussed in this section. The hardware design is unchanged from the Option III solution described in Reference 1. The firmware/software is modified relative to Option III to reflect the specific DSS-CD stability detection methods, which may include an upgrade to the Automatic Signal Processor card.

The DSS-CD design provides automatic detection and suppression of reactor instability events. Therefore, reliance on the operator to suppress instability events is minimized. The provision of a reliable automatic system makes the DSS-CD "operator friendly" in that protection does not rely on operator action. However, alarms are provided to alert the operator of an increase in the number of confirmed period counts so actions can be taken to avoid a reactor scram.

As described in Reference 3, a closely spaced group of LPRMs (1 to 8 LPRM detectors) is termed an Oscillation Power Range Monitor (OPRM) cell. Each of four independent OPRM channels consists of many OPRM cells distributed throughout the core so that each channel provides monitoring of the entire core. Thus, the system is fully capable of detecting both core wide and regional modes of oscillation. The system is "robust" in that it provides protection despite LPRM failures, OPRM cell inoperability (e.g., from too few inputs), or OPRM channels being out of service.

The CDA is designed to recognize an instability and initiate control rod insertion before the power oscillations increase much above the noise level. Defense-in-depth is provided by the LTS Option III detection algorithms, which are retained in the DSS-CD. These three algorithms examine aspects of the oscillation (local oscillation period, oscillation amplitude and oscillation growth rate) that may be present for oscillations that are not anticipated and are, therefore, not part of the DSS-CD licensing basis.

The CDA instability detection method and the MCPR performance confirmation analyses presented in this report provide a high confidence that the SLMCPR is not violated for anticipated oscillations, while minimizing the possibility of non-stability related scrams. The CDA capability of early detection and suppression of instability events is achieved by reliance on the successive confirmation period element of the PBDA. DSS-CD eliminates the reliance on the PBDA amplitude setpoint, which is included in the licensing basis of Option III. It introduces instead a fixed low amplitude OPRM signal discriminator, set just above the plant's intrinsic OPRM signal noise level. As a result, instability suppression occurs prior to any significant growth of oscillation amplitude for anticipated instability events.

The DSS-CD solution introduces a number of changes relative to the Option III solution. In addition, it introduces a number of modifications and restrictions to the successive confirmation period element of the PBDA to improve its ability for early recognition of reactor oscillations. These changes only affect the system software/firmware, and therefore, may be able to be implemented on-line.

To ensure adequate implementation of the DSS-CD solution and to avoid unnecessary spurious reactor scrams, the system may be checked while operable but not armed for the first reactor startup to power operation and controlled shutdown following DSS-CD implementation. During this initial system demonstration, proper alarm setpoint selection should be accomplished. In addition, system performance during normal operational maneuvers may be checked. For example, the system capability to accommodate the residual oscillatory behavior following a recirculation pump upshift/restart without generating an alarm or trip signal should be assessed. During this system check out period, reactor instability protection is provided by the BSP, described in Section 7.0.

The instability suppression by the DSS-CD for high growth instability events occurs within a few full oscillation periods from the time the instability is sensed by the Period Based Algorithm (PBA). Because the solution does not rely on oscillation growth to a specified high amplitude setpoint, suppression occurs within a short time from oscillation inception or close to the low amplitude OPRM signal discriminator and significant margin to the SLMCPR is provided. This inherent MCPR margin permits other elements of the solution's licensing basis to be demonstrated on a conservative basis, thereby simplifying the required evaluations.

In addition, conservatism is introduced in the design philosophy by selecting the SLMCPR to demonstrate protection of fuel cladding integrity for anticipated stability events. The SLMCPR is a conservative limit for this application because the fuel and clad responses to stability related oscillations are relatively mild even if the critical power ratio (CPR) falls below the SLMCPR. The DSS-CD initiated control rod insertion assures that the hot bundle only experiences a few oscillations prior to scram. If a fuel rod actually experienced Boiling Transition (BT), the cyclic nature of the event would result in clad rewet approximately every two seconds. A few oscillations in which the clad rewets would result in a negligible cladding temperature transient. This has been demonstrated in the assessment of Reference 4, showing that, as long as the clad rewets between cycles, the clad temperature increase is typically less than 100°F for oscillations up to 200% of rated power. Therefore, use of the SLMCPR as the acceptance criterion is conservative in protecting the fuel.

2.2 LICENSING COMPLIANCE

The DSS-CD solution and related licensing basis were developed to comply with the requirements of 10 Code of Federal Regulations (CFR) 50, Appendix A, "General Design Criteria for Nuclear Power Plants." The Appendix A criteria related to stability are Criteria 10 and 12.

Criterion 10 (Reactor Design) requires that:

> "The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences."

Criterion 12 (Suppression of Reactor Power Oscillations) requires that:

> "The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed."

The DSS-CD hardware and software are designed to reliably and readily detect and suppress both core wide and regional mode oscillations prior to violating the SLMCPR for anticipated oscillations. The ability to trip the reactor is automatically enabled at power and flow conditions at which stability related oscillations are possible.

To detect all expected oscillation modes, the outputs from closely spaced LPRM detectors are combined into OPRM cell signals. Thus, small regions of the core are effectively monitored for instabilities. Multiple cells distributed throughout the core provide input to each of the OPRM channels. This ensures that the system is sensitive to all of the anticipated oscillation modes, and also provides substantial redundancy for the input signals and accommodates out of service or failed LPRMs. A number of LPRM-to-OPRM cell assignments (i.e., number and location of the LPRMs that comprise the OPRM cells) are possible within the constraints of the OPRM definition given in Reference 1, as shown in Reference 3. There are no required changes in OPRM cell assignments from Option III to DSS-CD.

The DSS-CD licensing basis is designed to ensure that the system and setpoints result in suppression of oscillations before the SLMCPR is violated for anticipated instability events. In this context, anticipated oscillations are those which, based on both experience and analytical simulations, might be expected to occur in a reactor.

Anticipated instability events are defined to include core wide and regional mode oscillations with full core participation at reasonably limiting conditions and core designs. These events occur as a result of anticipated transients or normal operational maneuvers. All other instability events are considered unanticipated, including higher instability modes and limited core region participation (e.g., single channel oscillations). Unanticipated instability events occur as a result of unanticipated events or unplanned operator actions.

Protection against violating the SLMCPR for anticipated instability events is achieved solely by use of the CDA. No credit is taken for the other three algorithms that are provided as defense-in-depth protection against unanticipated oscillations.

Anticipated instability events are expected to gradually increase in amplitude and approach a limit cycle. The period of these oscillations becomes relatively constant (i.e., detectable) prior to the oscillation amplitude significantly exceeding the noise level, which allows early detection by the CDA. This is consistent with the observed behavior of actual plant instability events such as LaSalle-2 and Columbia and is consistent with the results of analytical simulations.

The licensing basis described in this report provides a high degree of confidence that power oscillations are terminated at relatively low amplitude by the DSS-CD solution, prior to any significant MCPR degradation, and therefore, obviates SLMCPR violations for anticipated instability events. Thus, the DSS-CD solution complies with GDC 10 and 12. The DSS-CD solution enhances overall plant safety by providing reliable, automatic oscillation detection and suppression function while avoiding unnecessary scrams.

2.3 DESCRIPTION OF REVISION 7 DESIGN APPROACH

This section provides an introduction and summary description for the key changes included in Revision 7.

i) The DSS-CD solution and application licensing basis is supported by two reports, NEDE-33147 and NEDC-33075. The first one provides the TRACG application to DSS-CD and the compliance with the CSAU methodology. The latter one is this report and provides the licensing basis and methodology to demonstrate the adequacy of the DSS-CD solution. Revision 3 of NEDE-33147 (Reference 19) and Revision 7 of this report are both based on TRACG04/PANAC11. The previous revision of both reports (NEDE-33147 Revision 2 and NEDC-33075 Revision 6) is instead based on TRACG02/PANAC10. Several TRACG results and the CSAU discussion were included in the previous revision of this LTR (NEDC-33075 Revision 6) because of timing issues with respect to the submittal of Revision 2 of NEDE-33147. The current revisions of the DSS-CD LTRs do not have such timing issues and therefore unnecessary duplications of TRACG results (i.e. already documented in Reference 19) were removed from this LTR. This includes, for instance, certain plots of TRACG traces for the selected stability transients and the discussion of the CSAU application. In this report, the MCPR margins and results provided in Section 4.0 are maintained and updated based on TRACG04/PANAC11 analyses.

ii) The previous revision of this report (NEDC-33075 Revision 6) included allowance to increase the amplitude discriminator setpoint above the generic [[ ]] recognizing the existence of high noise level in certain plants. Revision 7 provides a more clear and detailed description of the process to implement these higher amplitude discriminator setpoints for DSS-CD applications. On this regard, Section 3.3.1.9 is expanded and Section 4.7 is added in order to describe the basis and MCPR margins for higher than [[ ]] amplitude discriminator setpoints within a certain range. [[

]] Section 4.7 documents the complete description of the implementation process for any DSS-CD application with higher amplitude discriminator setpoint.

iii) The previous revision of this report (NEDC-33075 Revision 6) included [[ ]] cases recognizing the differences between these two plant product lines. In particular MCPR margins were [[

]] In addition, in Revision 7 two cases have been added for the [[

]] respectively. These cases were not included in the previous revision (NEDC-33075 Revision 6) because they were bounded by other scenarios. Although this is recognized to be still true, for completeness purpose these two additional cases were included in Revision 7. In Revision 7 the MCPR margins added for the higher than [[ ]] amplitude discriminator setpoints have been also [[

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iv) Revision 7 includes a few improvements in the BSP solution. These improvements are driven by the implementation of certain elements of the BSP solution based on what was learned from actual DSS-CD applications to the first few BWR plants. These improvements are related to the following four items. The description and the basis for each of these items are provided in Section 7.0:

1) ABSP Setpoint (see Section 7.5.4).

2) BSP Boundary (see Section 7.3).

3) BSP Controlled Entry Region (see Section 7.2.3.2).

4) BSP Region Boundary Shape Function (BSF) (see Section 7.2.1).

3.0 SOLUTION DESCRIPTION

This section provides a description of the major aspects of the DSS-CD solution. Some elements of the solution common to LTS Option III are contained in References 1 and 2. Where there are common elements, the description provided in this document is applicable to the DSS-CD solution. The arrangement of LPRM detectors into OPRM cells is discussed in Reference 3, and is summarized herein. The CDA and defense-in-depth algorithms are described in this section along with their key setpoints.

3.1 SYSTEM FUNCTION

The DSS-CD solution consists of hardware and software designed to reliably detect and suppress stability related power oscillations. The principal inputs to the system are the signals from a large number of LPRM detectors via the OPRM cell grouping. The signals are filtered, processed, and evaluated for evidence of stability related oscillations. If sufficient evidence exists that the reactor is experiencing unstable operation, a reactor scram is initiated by the Reactor Protection System (RPS).

The key function of the system is to automatically suppress stability related power oscillations to provide a high confidence that the SLMCPR is not violated for anticipated oscillations.

The DSS-CD solution includes four separate algorithms for detecting stability related oscillations:

- CDA,
- PBDA,
- ABA, and
- GRA.

All four algorithms perform calculations on each OPRM cell signal to determine if a trip is required. An illustration of the time of trip condition for each of these oscillation detection algorithms for a growing oscillation OPRM cell signal is depicted in Figure 3-1. The ability to trip the reactor is automatically enabled at power and flow conditions potentially susceptible to power oscillations. The trip enabled region is termed the Armed Region.

The PBDA, ABA and GRA detection algorithms provide the protection basis for LTS Option III, (Reference 3). They are retained in DSS-CD as defense-in-depth algorithms and are not needed to ensure compliance with the SLMCPR. Therefore, they are not part of the licensing basis for the DSS-CD solution, which is accomplished solely by the CDA. The PBDA, ABA and GRA offer defense-in-depth by providing protection for unanticipated instability events.

3.2 SYSTEM INPUT AND LPRM ASSIGNMENT

The basic input unit of the DSS-CD system is the OPRM cell. Reference 3 specifies that the OPRM cell consists of 1 to 8 closely spaced LPRM detectors. The signals from the individual LPRM detectors in a cell are averaged to produce the OPRM cell signal. For the DSS-CD solution the maximum number of LPRM detectors per OPRM cell is limited to 4. This limitation is introduced consistent with the solution setpoint determination, discussed in Section 3.3.1.4, and existing Option III plant-specific implementation designs.

The cell signal is filtered to remove noise components with frequencies above the range of stability related power oscillations. This is accomplished by a second order Butterworth filter with a cutoff frequency of 1.0 Hz (referred to as the "conditioning" filter), or equivalent. The conditioned signal is filtered again using a second order Butterworth filter with a shorter cutoff frequency of 1/6 Hz, or equivalent, to produce a time-averaged value. The conditioned and time-averaged signals are used by the four algorithms to detect reactor instabilities.

The assignment of LPRM detectors to specific OPRM cells can affect the system's ability to detect an oscillation. For example, a large number of detectors in a cell tends to reduce sensitivity to an oscillation due to the averaging of signals that are slightly out of phase with each other. Conversely, analytical results show that single LPRM cells are the most sensitive. Most plants are expected to use two to four LPRMs per cell to balance OPRM cell responsiveness and spurious trip considerations. Examples of possible LPRM to OPRM cell assignments are shown in Appendix D of Reference 3. The DSS-CD solution does not add new requirements to the LPRM to OPRM cell assignment other than the maximum limit of 4 LPRMs per OPRM cell constraint and the existing plant-specific cell assignments are acceptable.

Each OPRM cell is permanently assigned to an OPRM channel. A reactor scram occurs when any two or more OPRM channels trip. The DSS-CD solution does not add new requirements to the RPS logic and the existing plant-specific RPS logic is unchanged. For example, Figure 3-2 illustrates a typical "two-out-of-four" (2oo4) voted OPRM channel inputs to a typical "one-out-of-two-taken-twice" RPS logic, where a reactor trip occurs on any of the following Voters trips:

A1 & B1 or

A1 & B2 or

A2 & B1 or

A2 & B2.

3.3 LICENSING BASIS DETECTION ALGORITHM

The CDA provides the licensing basis protection for the DSS-CD solution. The design of the licensing basis algorithm provides automatic action to limit the size of the oscillations of anticipated events, thereby preventing SLMCPR violation.

3.3.1 Confirmation Density Algorithm

The CDA generates a reactor trip signal upon sensing the threshold of coupled neutronic/thermal-hydraulic instability just above the OPRM signal noise level. By suppressing oscillations at the instability threshold, where the reactor response is becoming coherent but not yet resulted in the growth of power oscillations with significant amplitudes above the intrinsic noise level, reliance on complex modeling of reactor trip setpoints based on transient MCPR behavior is negated.

The CDA utilizes the PBA, which is designed to recognize periodic oscillatory behavior in LPRM or OPRM cell signals (referred to herein as OPRM cell signals). The PBA is that portion of the PBDA that is associated with oscillation period recognition. The PBA is described in Section 3.4.1. The PBA application in support of the CDA requires certain modifications and restrictions relative to the Option III application. Those PBA modifications and restrictions are described in Section 3.4.1.1 and associated qualifications are described in Section 5.0. The PBA modifications and restrictions are applied for both the CDA and PBDA by the DSS-CD solution. In addition, the CDA employs a low amplitude OPRM signal discriminator to minimize unnecessary spurious reactor scrams for neutron flux oscillations at or close to the OPRM signal noise level.

The CDA identifies a Confirmation Density (CD), which is the fraction of operable OPRM cells in an OPRM channel that reach a target successive oscillation period confirmation count. When the CD exceeds a preset number of OPRM cells and when any of the confirming OPRM cell signals reaches or exceeds the amplitude discriminator setpoint, an OPRM channel trip signal is generated by the CDA. A reactor trip is generated when multiple channel trips are generated, consistent with the RPS logic design. By monitoring many OPRM cells for multiple successive oscillation period confirmations, the CDA can reliably and efficiently detect the transition to coherent core response, which is characteristic of a reactor at the threshold of instability.

In certain situations, periodic perturbations can be introduced into the thermal-hydraulic behavior of the reactor system (e.g., from control system feedback). These perturbations can potentially drive prolonged neutron flux oscillations within a frequency range expected for reactor instability. The presence of these oscillations is recognized by the CDA as reactor instability, independent of the actual stability of the reactor. Therefore, reactors that exhibit prolonged neutron flux oscillations that lie within the characteristic frequency range, but are not associated with coupled neutronic/thermal-hydraulic instability, may be susceptible to spurious scrams from the CDA instability detection method. For reactors that exhibit these prolonged neutron flux oscillations at the OPRM signal noise level, SLMCPR protection can be reliably maintained without increased susceptibility to spurious scrams by inclusion of the CDA signal amplitude discriminator. In cases when the CDA signal amplitude discriminator cannot adequately address these prolonged neutron flux oscillations, the plant may be susceptible to spurious scrams. In these situations, a higher signal amplitude discriminator setpoint may be justified or the CDA may be substituted with a different system for detecting the approach to core instability. Qualification of any alternatives or substitutes to the CDA is beyond the scope of the generic DSS-CD methodology, and requires application-specific resolution, review and approval.

3.3.1.1 Introduction

The power oscillation CD concept is predicated on the thermal-hydraulic behavior of a reactor under three distinctly different stability regimes. These regimes are stable reactor states, reactor instability threshold, and unstable reactor states.

A stable reactor has weak neutronic and thermal-hydraulic coupling, and normally exhibits small, random deviations from the steady-state neutron flux conditions. The response of a stable reactor to global noise perturbations quickly becomes incoherent. Either the response rapidly decays to the background noise level due to the stable core conditions, or subsequent unrelated perturbations disturb the natural decay characteristics. This characteristic behavior of a stable reactor inhibits the generation of many successive oscillation period confirmations, permitting the PBA to discriminate a stable reactor response from an unstable response.

At the threshold of instability, the reactor behavior is characterized by increasing neutronic and thermal-hydraulic coupling. This results in a coherent reactor response to global noise perturbations that is observable throughout the core. This phenomenon of coherent response is independent of the oscillation mode that eventually characterizes each instability event. As the core approaches an unstable state, most OPRM cells detect a periodic oscillatory response. This qualitative change in core behavior at the instability threshold results in a non-linear increase in the Successive Confirmation Count (SCC) that the PBA identifies in OPRM signals. At the threshold of instability, many OPRM cells simultaneously display oscillatory behavior due to the increased core coupling.

As a result of anticipated instability precursors, the reactor does not instantaneously transition to large amplitude neutron flux oscillations that mark core response beyond the instability inception. The characteristics of a reactor at the threshold of instability exist for a sufficient time to allow the PBA to detect the threshold condition. Specifically, the fraction of operable OPRM cells that exhibit a well-developed oscillatory signature increases from zero, before the instability threshold is reached, to a theoretical value of unity at the inception of instability. The PBA can therefore detect a significant number of successive period confirmations before the instability results in the growth in flux oscillation amplitude toward large, observable power oscillations that characterize an unstable reactor and threaten the SLMCPR.

These global characteristics of the coupled neutronic and thermal-hydraulic response to changes in core stability form the basis for the CDA methodology. Specifically, the CDA is able to recognize the instability threshold based upon the presence of multiple period confirmations from many OPRM cells. Following recognition of this condition, the CDA provides automatic protection of the fuel SLMCPR by generating a reactor trip signal prior to any significant growth in power oscillation amplitude.

The CDA methodology includes a low OPRM signal amplitude discriminator close to the typical OPRM cell signal noise levels. It avoids, however, the detailed characterization of MCPR performance as a function of growing power oscillations up to a high fixed amplitude setpoint, based on local neutron noise characteristics sensed by a few OPRM cells. As a result, the CDA methodology remains simple. In addition, the neutron noise based CD is expected to remain at zero until the reactor is at the instability threshold, at which time it rapidly approaches unity. This bi-stable behavior of the CDA eliminates the possibility of generating spurious trip signals for stable conditions based on the thermal-hydraulic behavior of the reactor.

3.3.1.2 Algorithm Basis

The CDA detects the presence of oscillatory behavior in the OPRM signal using the PBA. The PBA successive oscillation period confirmation count, for each OPRM cell exhibiting oscillatory behavior, increases in a highly non-linear manner at the instability threshold. In addition, the response of the core to global noise perturbations is observable over larger areas, causing many OPRM cells to exhibit oscillatory behavior.

Therefore, as the reactor DR approaches unity, and the reactor reaches the instability threshold, both the SCCs of individual OPRM cells and the number of OPRM cells generating multiple SCCs grow in an accelerated manner. A direct result of these qualitative changes in core response at the instability threshold is a non-linear increase in the fraction of OPRM cells reaching a target confirmation count, termed Successive Confirmation Count Threshold (N_{Th}). This fraction, which is the fraction of operable OPRM cells in an OPRM channel that exhibits an oscillatory response at or above N_{Th}, is defined to be the CD.

The theoretical relationship between CD and reactor DR is illustrated in Figure 3-3. The shape of the relationship assumes that the PBA is perfectly able to discern the oscillatory behavior of all OPRM cells, regardless of the oscillation mode. However, even with a perfect PBA, the relationship between the CD and DR at the instability threshold is not exact. The reactor conditions, growth rate, and the PBA system parameters are examples of elements that may affect the specific shape of this relationship.

The precise shape of the instability threshold band does not affect the qualitative transition in the CD to DR relationship between the stable reactor, instability threshold, and instability inception conditions. Figure 3-3 demonstrates the utility of the CD approach to provide automatic protection of the fuel SLMCPR from reactor instability. During stable reactor operations, DRs are typically low (DR < 0.4), with occasional increases into the moderate range (0.4 < DR < 0.7). For these reactor conditions, individual OPRM cell confirmation counts are not likely to reach the successive confirmation count threshold, and therefore the CD remains practically at zero. However, as soon as the instability threshold is approached (DR ≅ 1.0), the CD rapidly increases. This bi-stable characteristic of the CD, where the value remains at zero except at the instability threshold, when it rapidly transitions to unity, provides excellent discrimination between stable and unstable operations. As a result, the CDA avoids spurious trips, but can generate a reactor trip signal before oscillations develop significant magnitude.

Some of the operable OPRM cells may exhibit oscillation signatures incompatible with the PBA due to interference from neutron flux originating from areas of the core that are oscillating out-of-phase. This effect is particularly prominent near the axis of symmetry during first order regional mode oscillations. As a result, the maximum CD that is achievable in practice is less than one, as illustrated in Figure 3-4.

A CD setpoint (S^j_{CD}) is established for each OPRM channel, and defined to be the CD value for which a trip signal is generated. The setpoint is selected to ensure that an adequate number of OPRM cells exceed the successive confirmation count threshold, and that a sufficiently representative sample of OPRM cells is available for evaluation by the detection algorithm.

To minimize unnecessary spurious scrams not related to instability events, the CDA includes a low amplitude discriminator setpoint. Its purpose is to prevent a trip signal for situations when an oscillatory signature develops, which may be interpreted by the CDA as an instability event, but is occurring at a low amplitude and does not exhibit any significant amplitude growth. These situations may be associated with low amplitude, undeveloped instability events or reactor perturbation driven oscillations that are not related to coupled neutronic/thermal-hydraulic instability events. An Amplitude Discriminator State (AD_j) is established for each OPRM channel. An OPRM channel trip signal is generated when both the CD and amplitude discriminator trip conditions are met.

3.3.1.3 Algorithm Description

An OPRM cell instability threshold flag, S^i_{Th}, is introduced to indicate the status of the successive confirmation count, N_i, of the i^{th} operable OPRM cell relative to the successive confirmation count threshold (N_{Th}). It is defined as:

$$S^i_{Th} = \begin{cases} 0 & N_i < N_{Th} \\ 1 & N_i \geq N_{Th} \end{cases}$$

Whenever the successive confirmation count, N_i, for the i^{th} OPRM cell is reset to zero, S^i_{Th} is also reset to zero.

The j^{th} OPRM channel confirmation density, CD_j, is the fraction of OPRM cells exhibiting SCCs that are at or above N_{Th}, and is expressed as:

[[ ]]

where M^j_{OP} is the number of operable OPRM cells in the j^{th} OPRM channel and M^j_{RS} is the number of responsive OPRM cells in the j^{th} OPRM channel.

A certain number of OPRM cells may become inoperable during the course of an operating cycle. The CD is based on operable OPRM cells only. Therefore, inoperable OPRM cells are explicitly addressed by the CD setpoint definition.

[[

]]

An amplitude discriminator state, AD_j, is introduced to characterize the amplitude of all OPRM cells with confirmation count at or above N_{Th} (M_{CD}^{j}), corresponding to the j[th] OPRM channel, relative to the amplitude discriminator setpoint (S_{AD}). It is defined as:

[[

]]

The reactor instability threshold is identified by each OPRM channel and the j^{th} channel trip signal is generated when both, the j^{th} channel CD setpoint, S^{j}_{CD}, is reached and the j^{th} channel amplitude discriminator state, AD_j, is enabled:

$$CD_j \geq S^{j}_{CD} \quad \text{and} \quad AD_j = 1$$

A reactor trip signal is generated consistent with the plant-specific RPS system trip logic, when the required multiple channels trip signals are generated.

An alarm setpoint is included to provide an early indication of reduced stability margin. The alarms are not part of the licensing basis and the settings can be adjusted to support plant needs.

Table 3-1 summarizes the CDA process, setpoints and basis.

Implementation of the CDA requires the determination of the following setpoints:

a. Confirmation Density Setpoint (S_{CD}),

b. Successive Confirmation Count Threshold (N_{Th}),

c. Amplitude Discriminator Setpoint (S_{AD}), and

d. Alarm setpoint,

which are addressed in the subsequent sections.

3.3.1.4 Confirmation Density Setpoint Determination

In principle, the CDA uses the CD Setpoint (S^{j}_{CD}) to determine when the CD is equal to unity, which indicates the point of instability inception. In practice, however, the CD at the instability inception cannot be precisely predicted. Various factors such as oscillation mode and the relative efficiency of the PBA when applied to OPRM cells near the oscillation axis of symmetry, which is influenced by potential signal cancellation, effectively reduce the value of the CD at the instability inception to a value less than unity. An evaluation of OPRM cells participation during power oscillations is performed to establish the CD upper and lower bounds used to determine the CD setpoint.

Based on the CD model (Figure 3-4), instability threshold conditions exist for a finite time before instability inception occurs. The qualitative differences between stable reactor conditions and conditions at instability threshold are reflected in the strongly bi-stable behavior of the CD as a function of DR, and makes discrimination of the instability threshold straightforward. As a result, the CDA can protect the SLMCPR by appropriate selection of a reactor trip setpoint based on a conservative number of OPRM cells that are indicating instability threshold conditions, rather than attempting to precisely identify the condition of instability inception. Because of the availability of a large number of operable OPRM cells for use by the CDA, a bounding approach is taken to establishing an appropriate upper bound for the CDA trip setpoint.

The allowable CD setpoint upper bound (S_{CD}^{Max}) is given by:

$$S_{CD}^{Max} = (1 - E) \times F_{CD}^{Max}$$

E is defined to be the axial loss of PBA efficiency. The maximum response fraction, F_{CD}^{Max}, is defined to be the bounding maximum fraction of OPRM cells, ignoring axial PBA inefficiencies, that reaches N_{Th} at the point of instability inception. The values of E and F_{CD}^{Max} are selected to establish a permissible maximum value for the CD setpoint. The actual setpoint must be selected at or below this value to ensure proper operation of the CDA.

The neutron mean free path in highly voided core regions is comparable to the spacing between adjacent LPRMs. Therefore, during regional mode oscillations LPRMs in the top of the core can exhibit oscillatory behavior that is caused by the superposition of neutron flux originating from areas of the core on both sides of the oscillation symmetry axis. This composite signal can cause poor performance of the PBA in discriminating SCCs. As a result, E is generically set to 0.25 for OPRM cells that consist of a single LPRM, corresponding to the conservative assumption that the PBA is completely unresponsive to the D level (highest in the core) LPRMs.

For OPRM cell configurations that have more than a single LPRM per OPRM cell, one or more of the cell's LPRMs is at a level different than D. For these configurations, many of the OPRM cells do not include D level LPRMs. For those that include D level LPRMs, the OPRM cell response is typically dominated by the lower level LPRMs because the D level LPRM relative power is typically low. To maintain consistency with the conservative treatment of the single LPRM OPRM cell, E is generically set to 0.25 for all OPRM cell configurations.

The value of F_{CD}^{Max} is dependent on the mode of the power oscillations present in the core. A regional mode oscillation is conservatively selected as the limiting anticipated core behavior with respect to the CDA performance. LPRMs near the axis of symmetry can detect oscillations that are completely out of phase with the local thermal-hydraulic response. This condition is incompatible with the requirements of the PBA to discern SCCs. The size of the affected core area is governed by the neutron mean free path. Selection of a corresponding no-response zone width equivalent to 3 mean free paths on each side of the axis of symmetry provides approximately 95% attenuation of neutron flux from across the axis of symmetry, and bounds those LPRMs that may be affected by neutrons from the opposite oscillation phase. By conservatively using a small reactor design of 444 fuel assemblies, the maximum response fraction, F_{CD}^{Max}, for the assumptions described above is determined for OPRM cells with a single LPRM. Assuming an approximately even LPRM distribution in the core, a conservative estimate is established as:

F_{CD}^{Max} = 0.70 for single LPRM based OPRM cell

For most OPRM cells with more than a single LPRM, the selection of three mean free paths on each side of the axis of symmetry is conservative because the radial distribution of the LPRMs belonging to an OPRM cell provides a wider coverage. To maintain consistency with the conservative treatment of the single LPRM OPRM cell, F_{CD}^{Max} is generically set to 0.70 for all OPRM cells configurations.

The value of S_{CD}^{Max} is now determined based on the conservative estimates of the E and F_{CD}^{Max} values for all OPRM cell configurations:

$$S_{CD}^{Max} = (1 - 0.25) \times 0.70$$

or,

$$S_{CD}^{Max} \approx 0.5$$

The process of establishing the above estimate for the CD setpoint upper bound is illustrated in Figure 3-5. This value places a permissible upper bound on the CD Setpoint, S_{CD}^{j}, that is consistent with the requirement that the CDA generate a trip signal prior to or at the inception of reactor instability.

The estimate of F_{CD}^{Max} was confirmed using a PANACEA predicted response for an example BWR first order harmonic. The first harmonic contour from the PANACEA case is shown in Figure 3-6. Inside each fuel rectangle is the axial flux distribution for the corresponding bundle. The bottom of the core is on the left of each rectangle and the top of the core is on the right. The zero flux level is represented by a horizontal line through the center of the rectangle. In this case, first harmonic flux is positive in the lower left half and negative in the upper right half. Except for those fuel channels close to the harmonic axis, running from the northwest to southeast, the majority of the remaining fuel channels participate in the regional oscillations. The F_{CD}^{Max} value estimate based on the first harmonic contour is 0.8, which confirms the above estimate for all OPRM cell configurations.

A permissible minimum confirmation density setpoint, S_{CD}^{Min}, can also be established for S_{CD}^{j}. The minimum permissible value is not dictated by safety considerations. Instead, as S_{CD}^{j} decreases, the required number of OPRM cells reaching N_{Th} needed to generate a reactor trip signal becomes smaller. As a result, the CDA may become more sensitive to the characteristics of the instability threshold specific to a particular event and could potentially lead to a premature generation of reactor trip signals. To conservatively preclude this type of spurious actuation, a minimum number of OPRM cells are required to reach N_{Th} before the CDA generates RPS channel and reactor trip signals.

BWR experience to date has demonstrated that it is unlikely that the N_{Th} setpoint be exceeded for any OPRM cell during stable reactor operation in the Armed Region, where the system is armed. Moreover, for these conditions, it is not credible that multiple OPRM cells exceed the N_{Th} setpoint simultaneously. For certain OPRM cell configurations selected LPRMs may be grouped to 4 different OPRM cells. Therefore, a postulated dominating spurious LPRM oscillatory signature may affect the behavior of 4 different OPRM cells. To reduce the potential for spurious trip signals during stable reactor operation in the Armed Region, [[

]]

For plants requiring at least two LPRMs to maintain OPRM operability, the possible reduction in the number of responsive OPRM cells by M^j_{DL} can be eliminated by implementing LPRM to OPRM cell assignments that include no more than one D level LPRM in each OPRM cell. For these configurations, OPRM cells with exclusive input from D level LPRMs include only a single operable LPRM, and are therefore declared inoperable. Example LPRM to OPRM cell assignments are shown in Appendix D of Reference 3.

[[

]]

3.3.1.5 Successive Confirmation Count Threshold Determination

The CDA utilizes the successive confirmation count threshold (N_{Th}) to discriminate the stability characteristics of individual OPRM cell SCCs generated by the PBA. The choice of N_{Th} is based on two considerations.

[[

]] Because the reactor is not anticipated to instantaneously transition to unstable, growing power oscillations, this CDA response time provides adequate protection of fuel SLMCPR for anticipated instability events.

3.3.1.6 Amplitude Discriminator Setpoint Determination

The CDA utilizes the amplitude discriminator setpoint (S_{AD}) to prevent CDA-generated trip signals at the naturally occurring OPRM signal noise level. The choice of S_{AD} is based on two considerations.

[[

]]

3.3.1.7 Single Loop Operation

Application of the TLO CDA setpoints to SLO may result, under certain operating conditions, in excessive unnecessary spurious scrams. [[

]]

3.3.1.8 Alarm Setpoint Determination

The CDA provides automatic indication of reductions in stability margin to alert the operator of possible approach to the instability threshold when operating inside the Armed Region. With an appropriately selected alarm setpoint, sufficient time for manual operator action may exist for transients that cause a gradual erosion of reactor stability margin from stable reactor operating conditions. This CDA alarm capability is provided in addition to the alarm being actuated upon entry into the Armed Region, which is designed to alert the operator that an entry into a region potentially susceptible to reactor instability had occurred.

The CDA alarm setpoints, the successive confirmation count (N_{AI}) and the amplitude (S_{AA}) components, are selected on a plant-specific basis to ensure that no spurious alarms occur during stable plant operation. The alarm setpoints may be applied to the leading OPRM cell. The alarm occurs when the successive period confirmation count for any single OPRM cell (in any OPRM channel) reaches N_{AI} and its amplitude exceeds S_{AA}. Alternatively, the alarm setpoint may be applied to the second confirming OPRM cell (i.e., provided a single OPRM cell exceeds N_{AI}, the alarm is generated when any additional OPRM cell in the same OPRM channel exceeds both N_{AI} and S_{AA}). The CDA alarm may be implemented with another means of stability monitoring (e.g., on-line stability predictor or monitor) to improve the capability to predict gradual changes in stability margin. The alarm setpoint and its parameters (S_{AA} and N_{AI}) are a non-licensing basis features added to provide a meaningful alarm to the operators and to limit the occurrence of nuisance alarms.

The selection of a specific alarm setpoint value and definition of the associated operator actions are operational considerations and depend on the plant-specific neutron flux noise characteristics and operational preferences and are not addressed in this report. Because the CDA alarm function has no effect on the system automatic protection capability, the choice of the plant-specific alarm setpoint is optional and is not subject to any generic or plant-specific requirements. Therefore, from a licensing perspective, any alarm option selection is acceptable.

The alarm function is not required during rated power operation outside the Armed Region, where the system is operable but not armed. Although the alarm function is not armed during operations at core flow above the Armed Region, the alarm function is automatically armed upon entry into the Armed Region.

3.3.1.9 Generic Setpoints Application

[[

]] Therefore, each initial plant-specific application for DSS-CD will include a comparison of the resulting margins to the SLMCPR and the margins presented in the DSS-CD LTR.

In summary, the application of [[

]]

3.4 DEFENSE IN DEPTH ALGORITHMS

The PBDA, ABA and GRA offer defense-in-depth by providing protection for unanticipated instability events. These algorithms are not required to provide licensing basis protection for the SLMCPR within the DSS-CD solution.

The design objective for the defense-in-depth algorithms is to provide automatic action to limit the size of the oscillations of unanticipated events, thereby preventing fuel cladding damage. As demonstrated in Reference 4, power oscillations up to 200% of rated power produce a temperature transient such that no cladding failure would be expected. The defense-in-depth detection algorithms offer a higher degree of assurance that fuel failure does not occur as a consequence of unanticipated stability related oscillations.

Table 3-4 lists the DSS-CD defense-in-depth algorithm recommended setpoints. The choice of setpoints for the ABA and GRA is consistent with References 1 through 3. For the PBDA, nominal setpoint values are recommended on a generic basis. These setpoints would reasonably limit the size of unanticipated stability related power oscillations. They are selected to provide early protection without significantly increasing the likelihood of a spurious scram not related to instability events. The defense-in-depth trips with the specified setpoints provide backup protection greater than that provided by the APRM high flux scram, in particular for the regional mode of oscillations. No further analysis is required to justify these setpoints.

3.4.1 Period Based Detection Algorithm

The PBDA is described in References 1 and 2. The PBDA utilizes the observation that LPRM noise becomes progressively more coherent during the approach to the inception of an instability event, before the amplitude becomes large. The PBDA uses a combination of period confirmation count and amplitude setpoint to determine if a trip is required. The period confirmation count portion of the PBDA is referred to as the PBA. It constitutes the entire algorithm with the exception of the amplitude aspect.

According to Reference 1, the PBA focuses on the periodicity of the oscillation in the approximate range from 0.3 to 0.7 Hz, or the equivalent time period limits (T_{min} and T_{max}). T_{min} and T_{max} are conservatively selected to bound the anticipated instability frequency range. The algorithm interrogates the OPRM cell signal based on a short sample time (t_i). When the time difference between successive peaks (or successive minima) in an OPRM cell signal is consistent with the time period limits, this time difference is defined as the base period, T_0. The next period (T_1) calculated between successive peaks (or minima) must be within a small time window, period tolerance ($\pm$ ε), of T_0 to produce a "confirmation" that oscillatory behavior exists. A new base period is defined as the average of all consecutively confirmed periods in that cell. Based on evaluation of plant data, as the DR increases toward 1.0, the oscillation period becomes constant, resulting in many consecutive confirmations. If a successive period is not confirmed to be within the period tolerance of the base period, the period count is reset to zero and the search for a new base period is initiated. The PBA period confirmation process is illustrated in Figure 3-9.

The PBDA is programmed to identify an instability based on the occurrence of a fixed number of consecutive period confirmations, which is considered evidence of a stability related power oscillation. A trip is generated for an OPRM cell (and hence for that RPS channel) if:

1. The number of successive period confirmations exceeds its setpoint value (N_p), and
2. The relative signal exceeds a specified amplitude setpoint, S_p.

The value of S_p is set sufficiently above the noise level to minimize the likelihood of an inadvertent scram. Consequently, the PBDA generates a trip when oscillatory behavior consistent with an instability exists and the peak-to-average cell signal has increased to the trip amplitude setpoint. This balances the probability that the system trips when needed to suppress an instability event and does not trip when it is not required.

For DSS-CD, the PBDA successive period confirmations setpoint, N_p, is selected above the CDA setpoint (i.e., 15). This setpoint is representative of the higher end of the range provided in Reference 3, Appendix E. This selection is made to further reduce the likelihood of a spurious scram by the PBDA, which is appropriate because the PBDA is a DSS-CD defense in depth algorithm that is not required to demonstrate SLMCPR protection.

For the CDA amplitude setting (S_{AD}) range described in Section 4.0, a separation between the CDA amplitude and the PBDA amplitude, S_p, is required to prevent a defense-in-depth algorhitm amplitude related actuation prior to the CDA. A separation in 0.05 amplitude is reccomended between the S_p and S_{AD} setpoints, based on the on the following relationship:

[[ ]]

The PBDA amplitude setpoint, S_p, is selected per the relationship above consistent with the other defense-in-depth algorithms, to provide protection at the ABA and GRA amplitude detection threshold (S_1).

References 1 and 2 define two adjustable parameters that affect period confirmations, and are used to achieve proper plant-specific system calibration, the period tolerance (ε) and the conditioning filter cutoff frequency (f_c). Based on existing experience and to ensure adequate instability detection by the PBA, these parameters' values are fixed for DSS-CD applications, and are not subject to adjustment. The assigned values for these parameters have been demonstrated to provide continuous confirmations upon transition from stable reactor operation to a growing reactor instability. Specifying the parameters' values provides assurance that the PBDA provides sufficient confirmations for a growing reactor instability.

Based on testing of the algorithm against available plant data and DSS-CD specific considerations (see below), the acceptable parameter values are specified in Table 3-5. The conditioning filter cutoff frequency value is selected at 1 Hz to ensure efficient filtering of high frequency noise components, which is critical for proper PBA functioning during the development of reactor instability events. The conditioning filter cutoff frequency has been shown to have little effect on the PBA SCC during stable operation. The period tolerance value is selected at 100 msec to ensure adequate period confirmation during the development of reactor instability events, which is supported by existing instability event experience. This value, however, may result in increased PBA SCC during stable operation, which need to be considered in the selection of the CDA alarm setpoint.

The normalized OPRM signal processed by the PBA is constructed as the ratio of the filtered input signal to the OPRM signal average. Reference 2 specifies that a typical range for the time constant associated with the signal averaging process is 5 to 7 seconds. This range provides an appropriate signal average value for steady state or quasi steady state operation. However, the averaged signal may significantly lag the input signal during a fast transient, such as a significant flow reduction event from rated power operation. Because MELLLA+ operation may result in off-rated conditions that are inherently unstable following a flow reduction event, instability may develop during the time the averaged signal is lagging and the normalized signal is inappropriately low.

To address this concern, an averaging filter cutoff frequency of 1/6 Hz (or an equivalent time constant of 0.95 seconds) is used for DSS-CD, which substantially reduces the averaged signal lag (the transition band is reduced from close to 30 seconds to approximately 5 seconds). This cutoff frequency value provides less effective averaging process during steady state operations, resulting in low amplitude residual oscillations. However, because the cutoff frequency value is sufficiently low, the average signal exhibits only insignificant amplitude variations for the signal amplitude range up to the DSS-CD PBDA amplitude setpoint. A parametric study of the normalized signal performance with the 1/6 Hz filter cutoff frequency for the detection algorithm oscillation period range ([[ ]]) has demonstrated that the normalized signal values are always conservative (i.e., higher) during steady state operations. Therefore, the use of the 1/6 Hz averaging cutoff frequency eliminates the concern of significant normalized signal lag following a fast flow reduction event, and ensures a conservative normalized signal value during oscillations relative to the DSS-CD PBDA amplitude setpoint.

3.4.1.1 PBA Application for CDA

A number of modifications and restrictions for the Option III PBA version (Reference 3) are required for the proper application of the PBA in the CDA. [[

]] These PBA modifications and restrictions are also used for the PBDA, [[

]]

Significant flow reduction events from power operation may result in operating conditions that are unstable. This is more likely for 2RPT events that initiate from the rated power and minimum flow conditions. Because the reactor state condition is rapidly changing during the 2RPT event, the ensuing oscillations are not developed instantaneously. The transition to a coherent oscillation mode involves the alignment of the entire core, which not only requires some limited duration but also may exhibit transitional effects. In particular, the oscillation frequency, and therefore, the detected period for individual channels may exhibit modulated behavior.

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The time period limits specified in Table 3-4 conservatively envelop the range of characteristic periods anticipated for all DSS-CD applications addressed by this report. [[

]]

3.4.1.2 PBA Signal Sampling and Resolution for DSS-CD

The PBA evaluates a discrete representation of the OPRM cell input signal that depends on the signal sample rate. The signal sample rate is selected to ensure that signal periods, which fall within the specified algorithm frequency range, contain a large number of samples. Discretization of the input signal creates the possibility of shifts in the number of time step intervals associated with a single period. For an input signal with a constant period, variations of plus or minus one time step relative to the average number of time steps per period may occur. If the selected period tolerance value is equal to the sampling time step, occasional reset of the SCC for a fully periodic signal may occur due to shifts in the time step count per period.

The base period is equal to a whole multiple of the sampling time step for each SCC. A single occurrence of a period with one less time step than the base period count reduces the base period by one time step. If the subsequent period contains one more time step than the original base period, the difference between the current period and the base period is more than one time step. As a result, the period tolerance criterion is violated when it is equal to the sampling time step and results in an erroneous SCC reset. A SCC reset also occurs with the reverse scenario, when the higher time step count per period is encountered prior to the lower count.

To ensure that a continuous SCC is generated for a periodic OPRM cell signal within the PBA range, the theoretical minimum period tolerance is related to the discretization of the OPRM cell signal by the following relationship:

$$\varepsilon = \text{Max}\ (\varepsilon_{\text{Input}}, 2 \times \text{Signal sampling time step})$$

where ε_{Input} is the PBA period tolerance selection available and ε is the resultant period tolerance.

The DSS-CD solution design requires a criterion specifying the minimum acceptable resolution of the OPRM cell signal amplitude. Appropriate selection of this criterion ensures that under all anticipated reactor conditions approaching reactor instabilities the system is capable of performing its design functions, including the identification of successive signal minima and maxima and characterization of signal period.

Reactor two recirculation loop operations in regions of the operating domain susceptible to reactor instabilities are typically associated with a nominal peak-to-average OPRM noise amplitude of 1 to 2%. This amplitude is dependent on the specific reactor conditions and may vary from plant to plant. However, the peak-to-average range is characteristic of stable reactor operation. During the approach to reactor instabilities, peak-to-average amplitudes increase from those associated with stable reactor operation amplitudes.

To ensure the system is designed with an acceptable signal amplitude resolution, the criterion specifying the minimum acceptable resolution of the OPRM cell signal peak-to-average amplitude difference is set at 1% of scale. This value represents the lower bound of typically observed peak-to-average amplitudes during stable reactor operation, and is conservative for conditions approaching reactor instabilities. Application of this criterion ensures that the system is capable of successfully identifying successive minima and maxima for periodic signals, with peak-to-average amplitude difference of 1% of scale or higher, for the full frequency range expected for reactor instabilities.

3.4.2 Amplitude Based Algorithm

The ABA is described in References 1 and 2. The value of the OPRM cell relative signal is compared at each detection time step to a threshold setpoint, S_1 (greater than 1.0). If the relative signal exceeds S_1, then the algorithm checks to determine if the relative signal decreases to a second setpoint, S_2 (less than 1.0), within a time period typical of an instability oscillation. If the signal goes below S_2 in the expected time window (T_1), then the algorithm looks for the next peak in the relative signal. Then, if the relative signal exceeds the trip setpoint, S_{max}, in the expected time window (T_2), a trip is generated for that OPRM cell (and hence for that RPS channel). Recommended values for S_1, S_2, S_{max}, T_1, and T_2 are given in Table 3-4.

3.4.3 Growth Rate Algorithm

The GRA is described in References 1 and 2. It examines OPRM cell signals for rapidly growing oscillations. As for the ABA, the value of the OPRM cell relative signal is compared at each detection time step to a threshold setpoint, S_1 (greater than 1.0). If the relative signal exceeds S_1, then the algorithm checks to determine if the relative signal decreases to a second setpoint, S_2 (less than 1.0), within a time period typical of an instability oscillation. If the signal goes below S_2 in the expected time window (T_1), then the algorithm looks for the next peak in the relative signal. A trip signal is generated by the GRA if the setpoint S_3 is exceeded in the expected time window. S_3 is calculated from the peak of the previous cycle (P_1) and the desired maximum allowable growth rate (GR_3):

$$S_3 = GR_3 \times (P_1 - 1.0) + 1.0$$

If the signal goes above S_1, then below S_2 in the expected time window, and then exceeds S_3 within the expected time window, a trip is generated for that OPRM cell (and hence for that RPS channel). The GRA uses the same values for S_1, S_2, T_1, and T_2 as the ABA. Recommended values for S_1, S_2, GR_3, T_1 and T_2 are given in Table 3-4.

3.5 SYSTEM OPERABILITY

To provide its specified stability protection function, the DSS-CD system is required to be operable in Mode 1 at all times and is automatically armed inside the solution Armed Region, as described in Section 4.5. Alternatively, the DSS-CD may be required to be operable above a power level set at 5% of rated power below the lower boundary of the Armed Region defined by the MCPR monitoring threshold power level. This alternative method is acceptable because system operability is assured prior to entry into the Armed Region.

For operation outside the Armed Region, the system is disarmed to reduce the probability of spurious scrams and alarms, but maintained operable at all times. If the system licensing basis protection is not assured, a supplemental backup, as specified in the plant Technical Specifications, is required. Example BSP approaches are described in Section 7.0. Other backup approaches that are justified to provide protection similar to the BSP may also be used. Backup protection is required when the DSS-CD is bypassed.

Table 3-1 Confirmation Density Algorithm Setpoints and Basis

Process Step	Algorithm	Definition and Setpoint	Basis and Notes
Determination of OPRM cell Instability Threshold Flag (S^i_{Th}) state	$S^i_{Th} = \begin{cases} 0 & N_i < N_{Th} \\ 1 & N_i \geq N_{Th} \end{cases}$	N_i = SCC of the ith OPRM cell N_{Th}= Successive Confirmation Count Threshold [[ ]]	– OPRM cells or single LPRMs may be used – S^i_{Th} is set to 1 at signal extremum only if the confirmation count is equal or above N_{Th} – S^i_{Th} is reset on count reset for the i^{th} OPRM cell – [[ ]]
Determination of j^{th} OPRM channel CD_j	[[ ]]	M^j_{RS} = Number of responsive OPRM cells for j^{th} OPRM channel M^j_{OP} = Number of operable OPRM cells for j^{th} OPRM channel $M^j_{RS} = M^j_{OP} - M^j_{AX} - M^j_{DL}$	– Operable OPRM cells require at least 1 operable LPRMs – [[ ]]
Determination of j^{th} OPRM channel AD_j	[[ ]]	P^j_i = Last recorded peak of i^{th} OPRM cell normalized signal for j^{th} OPRM channel M^j_{CD} = Number of OPRM cells at or above N_{Th} for j^{th} OPRM channel S_{AD} = Amplitude discriminator setpoint [[ ]]	– [[–]]
Trip signal for j^{th} RPS channel by comparison with CD setpoint (S^j_{CD}) and AD_j	$CD_j \geq S^j_{CD}$ AND $AD_j = 1$	S^j_{CD} = j^{th} channel CD setpoint [[ ]]	– [[–]]
Neutron Monitoring System (NMS) trip signal	System architecture	e.g., one-out-of-two, twice	– Adheres to NMS requirements of divisional separation and redundancy
NMS alarm signal	$N_i \geq N_{Al}$ $S_i \geq S_{AA}$	N_{Al} = Successive confirmation alarm setpoint S_{AA} = Amplitude alarm setpoint	– Early indication of reduced stability margin – Applied to leading or second OPRM cell – Determined based on plant-specific performance

Table 3-2 444 Bundle Core OPRM Channel Operability and CD Setpoint Illustration

(OPRM map assignment per Figure 3-7 and OPRM cell operability requirement of at least one operable LPRM)

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	– – –					
	– –					
	– –					
	– –					

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Table 3-3 624 Bundle Core OPRM Channel Operability and CD Setpoint Illustration

(OPRM map assignment per Figure 3-8 and OPRM cell operability requirement of at least two operable LPRMs)

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	– –					
	– –					
	– –					
	– –					

]]

Table 3-4 Defense in Depth Algorithm Setpoints*

Algorithm	Setpoint	Value
PBDA	N_P	15
PBDA	S_P	[[ ]]
PBDA	T_{min}, T_{max}	[[ ]]
ABA, GRA	S_1	1.10 – 1.20**
ABA, GRA	S_2	0.85 - 0.95**
ABA	S_{max}	1.30 – 1.50**
GRA	GR_3	1.30 – 1.60**
ABA, GRA	T_1 (time window)	0.3 to 2.5 seconds
ABA, GRA	T_2 (time window)	0.3 to 2.5 seconds

Notes:

* These are not licensing basis parameters and can be changed. This table provides the ranges and values currently recommended by GEH.

** Ranges provided consistently with Reference 2.

Table 3-5 PBA Parameters

Parameter	Value
ε - Period Tolerance (milliseconds)	100
f_c - Conditioning Filter Cutoff Frequency (Hz)	1.0

Figure 3-1 DSS-CD Detection Algorithms Time of Trip Condition Illustration

[[

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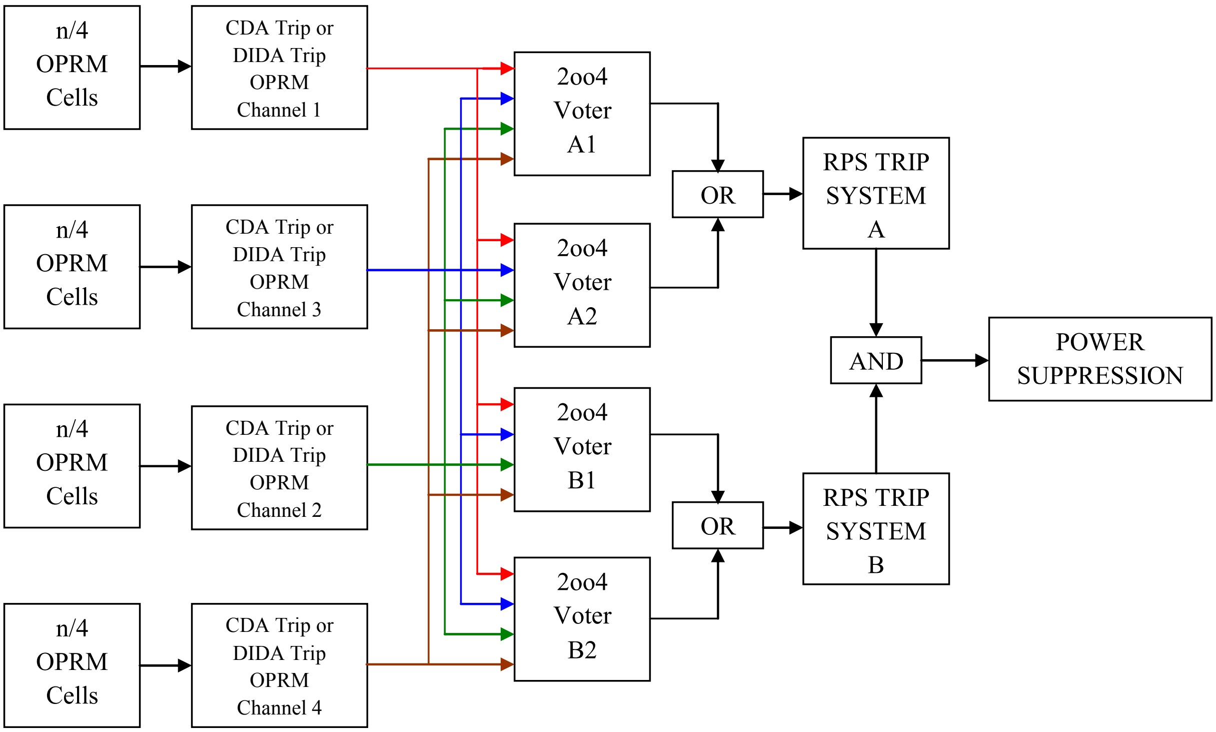
Figure 3-2 Example RPS Trip Logic



Notes:

- n total OPRM Cells
- DIDA Trip = PBDA Trip or ABA Trip or GRA Trip
- The CDA and DIDA Trips are voted independently by each Voter.

Figure 3-3 Theoretical Confirmation Density as a Function of Decay Ratio

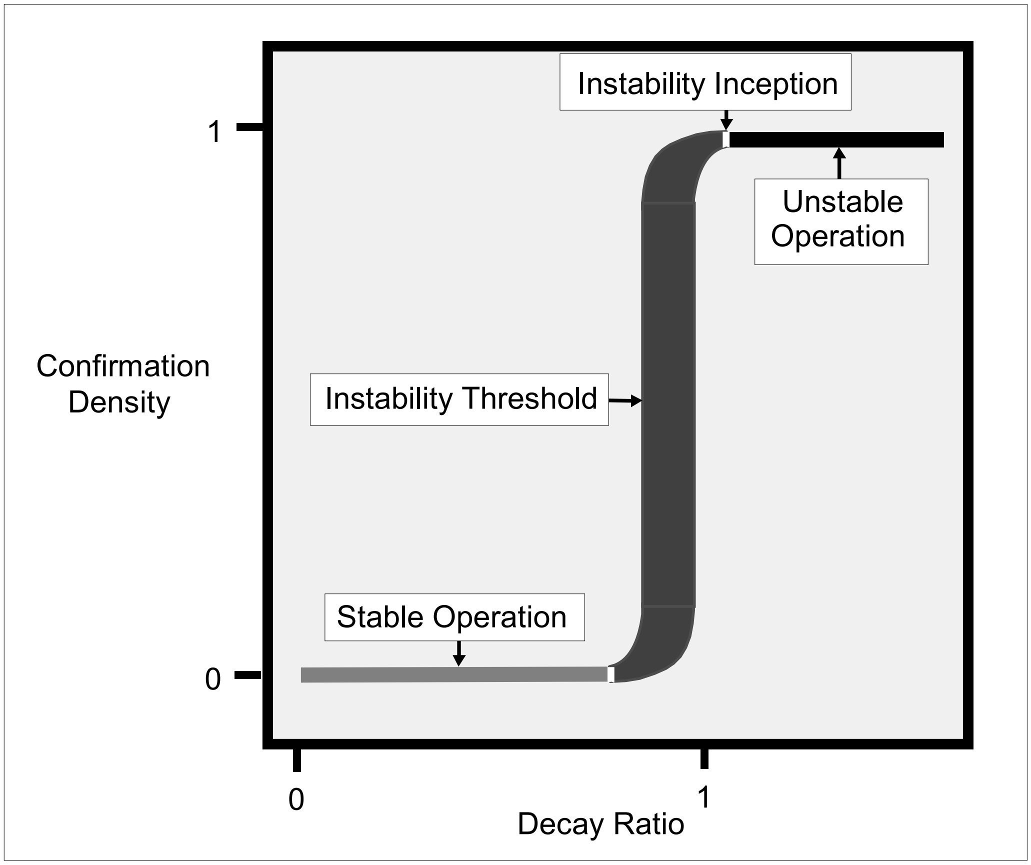


Figure 3-4 Practical Confirmation Density as a Function of Decay Ratio

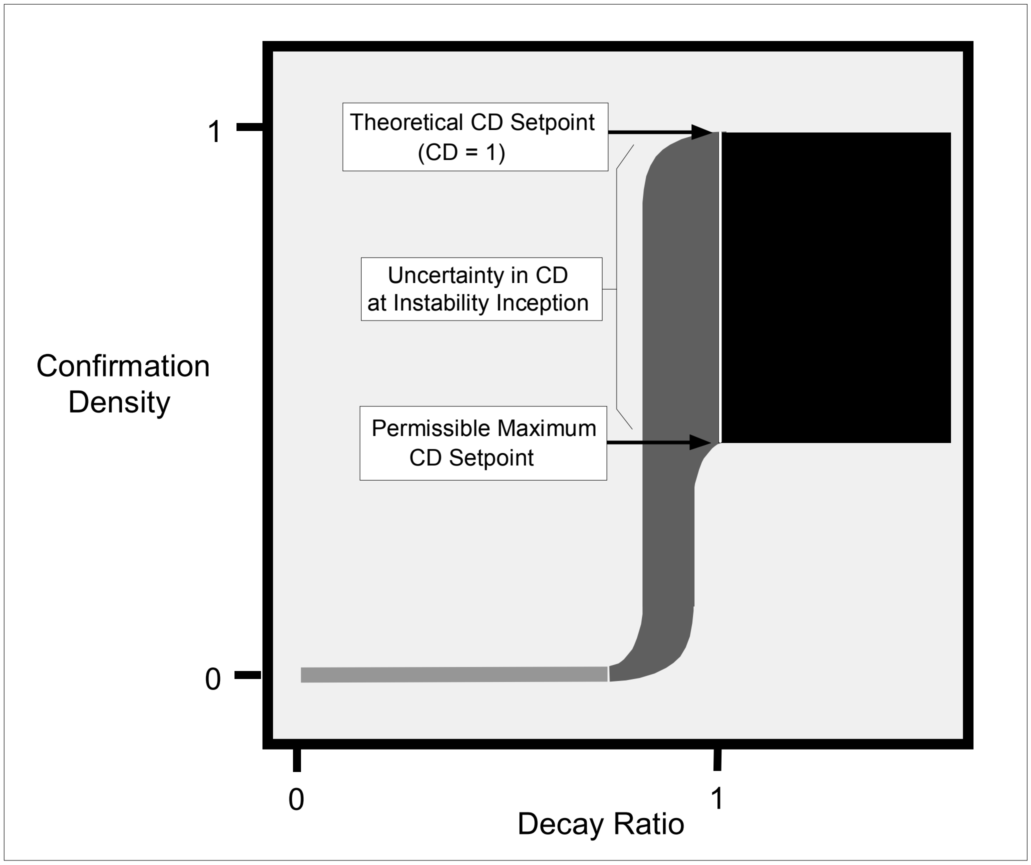


Figure 3-5 Core Volume Corresponding to CD Upper Bound

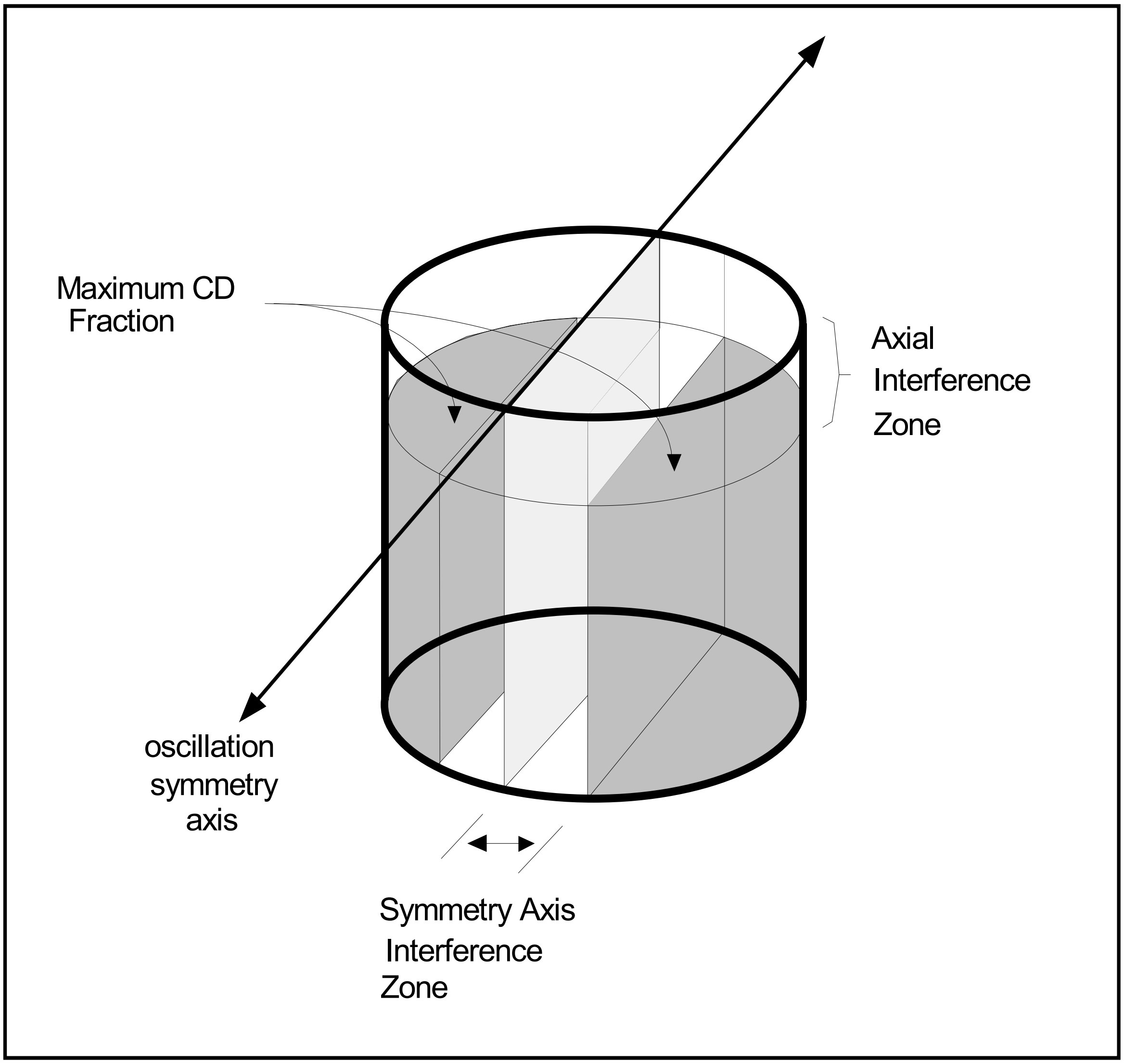


Figure 3-6 PANACEA Contour for a Typical BWR First Order Harmonic

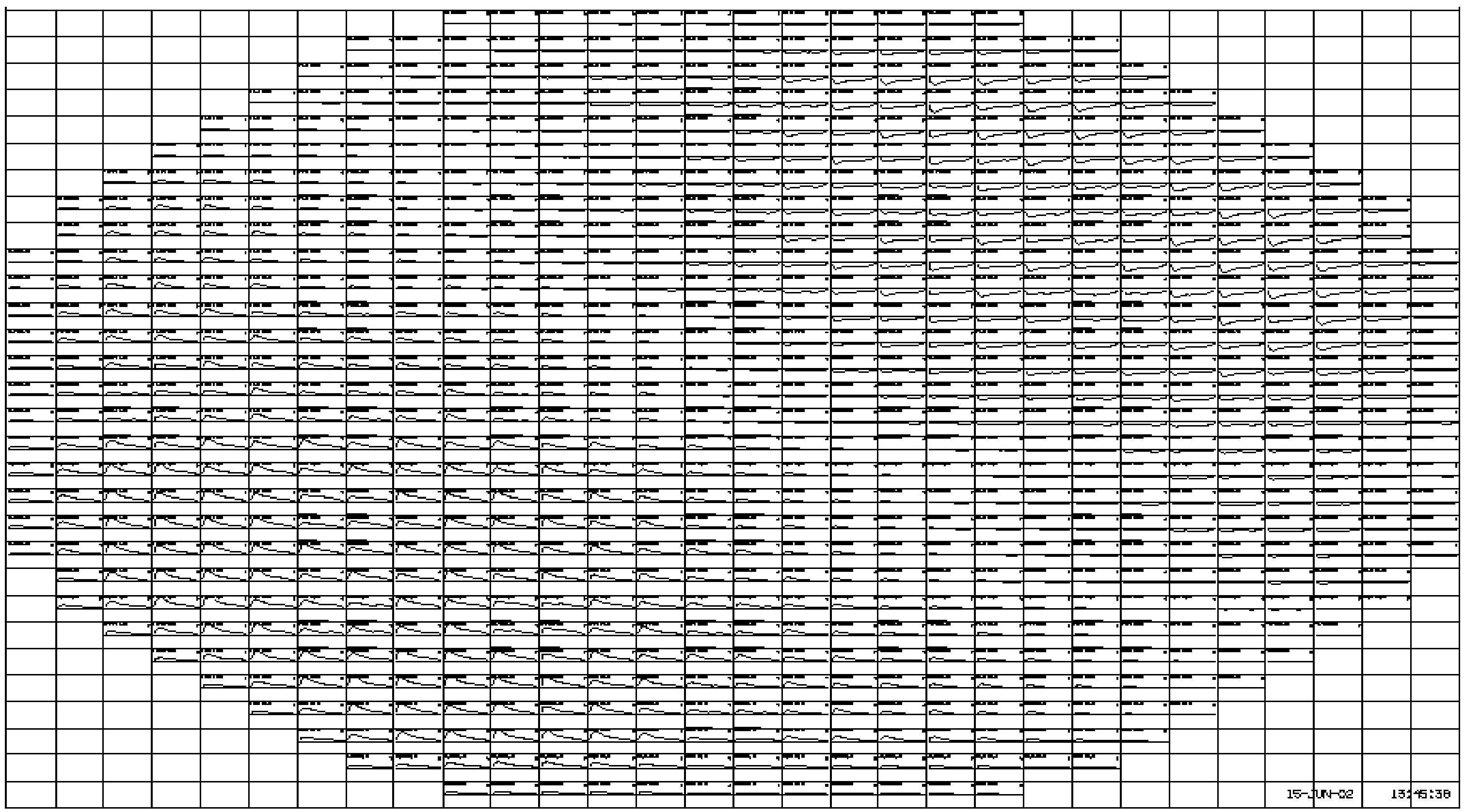


Figure 3-7 OPRM Channel Assignment Map for 444 Bundle Core

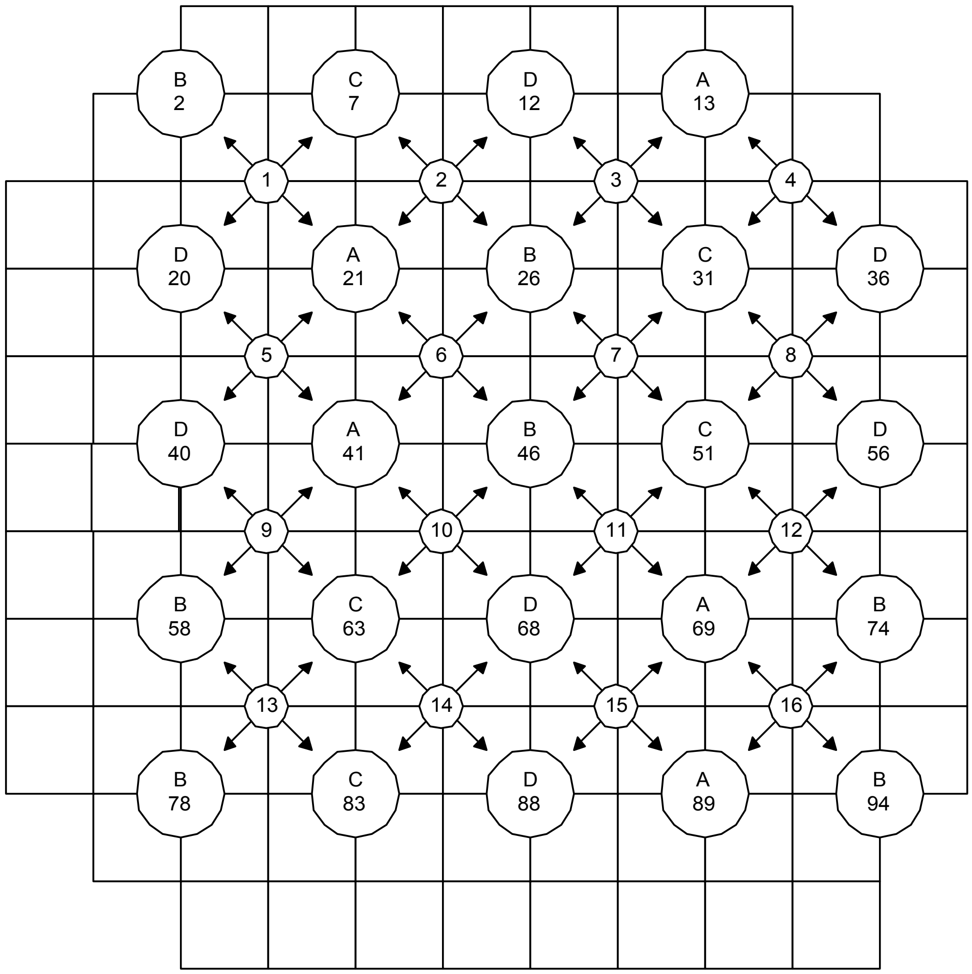


Figure 3-8 OPRM Channel Assignment Map for 624 Bundle Core

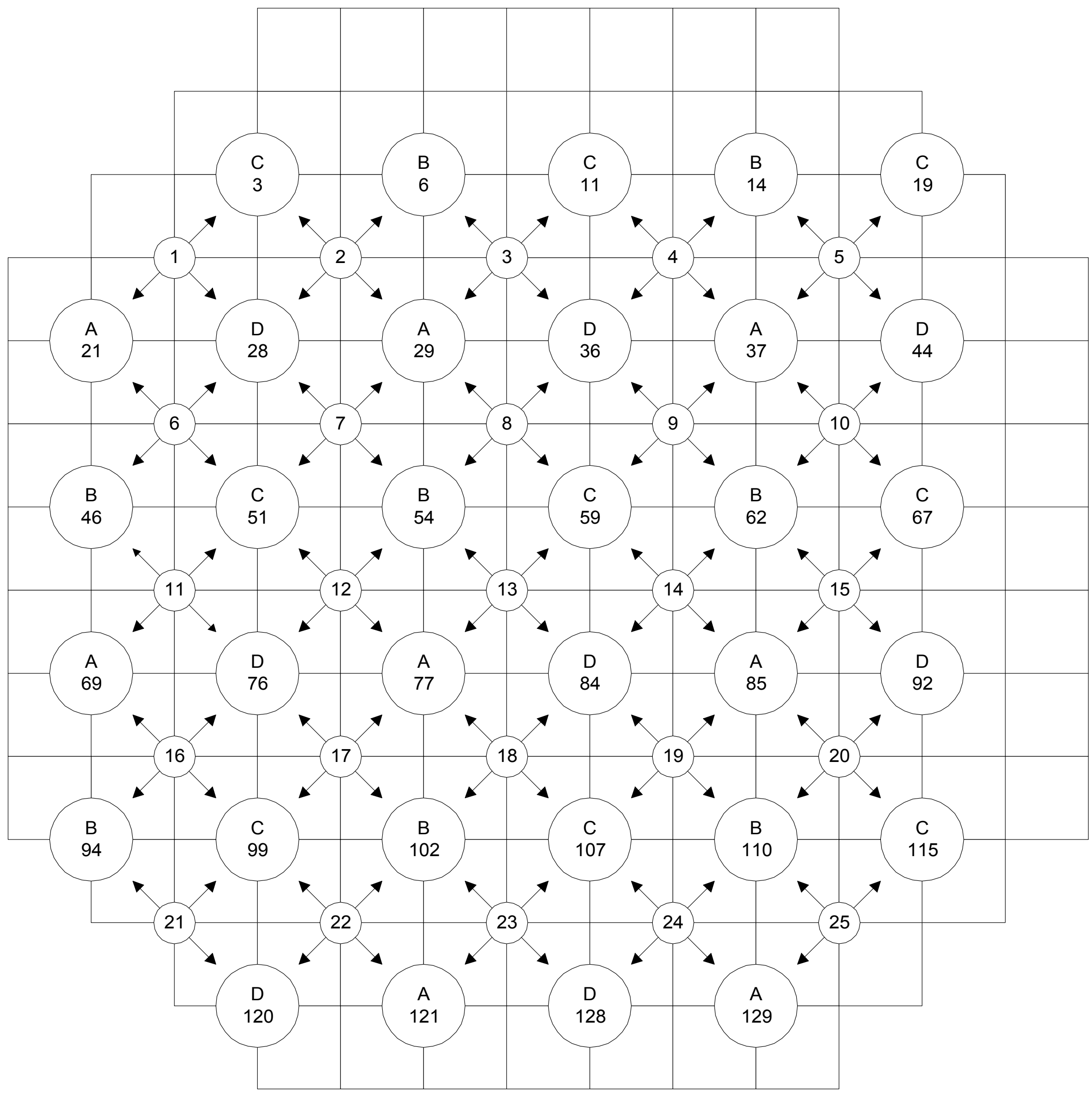
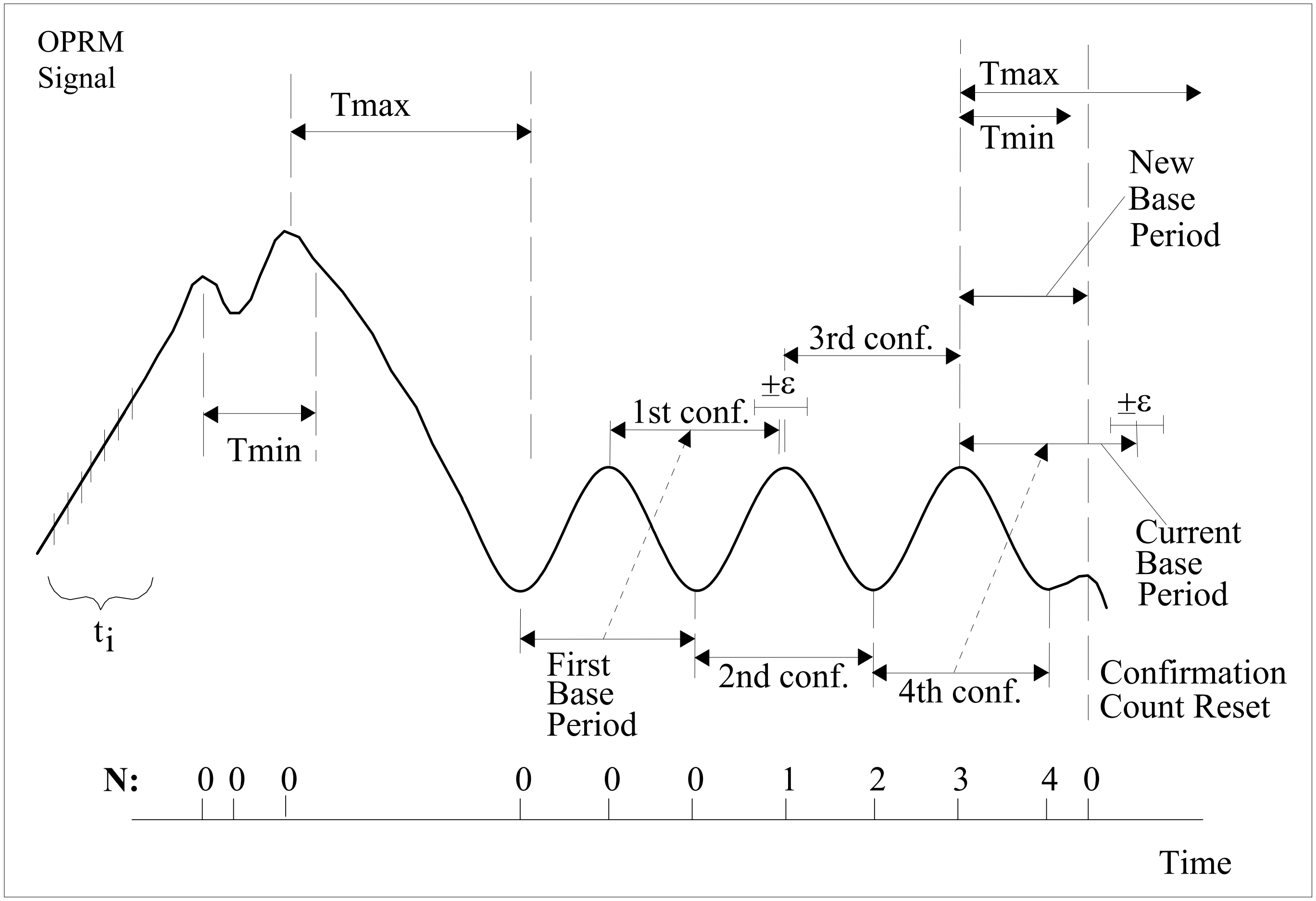


Figure 3-9 PBA Successive Period Confirmation Process



4.0 LICENSING BASIS

4.1 OVERVIEW

This section demonstrates on a generic basis that the DSS-CD system and its associated setpoints result in timely suppression of oscillations without violating the SLMCPR for anticipated instability events. A plant-specific confirmation assessment is performed whenever design changes beyond a specified generic applicability envelope are introduced that may affect stability performance and for each cycle to ensure that the generic DSS-CD basis remains valid for plant reload applications.

The presence of reactor instability can challenge the fuel SLMCPR. This occurs when fuel cladding heat flux and channel coolant flow rates deviate from steady state conditions during power oscillations significantly above the normal neutron noise level. To comply with GDC 12, protection of the SLMCPR can be accomplished by either detecting and suppressing instability induced power oscillations, or preventing them altogether.

The existing "detect and suppress" algorithms of LTS Option III (Reference 3) are based on a common approach. An OPRM cell signal oscillation, consistent with that characteristic of the reactor thermal-hydraulic oscillation frequencies, is identified. The presence of these characteristic power oscillations is then confirmed by various methods. The PBDA monitors successive oscillation periods and provides an oscillation amplitude trigger to generate a reactor trip signal. The GRA consists of an oscillation growth rate limit, which if exceeded, generates a reactor trip. Finally, the ABA consists of an oscillation amplitude limit, which if exceeded, generates a reactor trip.

The Option III licensing basis (Reference 3) relies on the PBDA, with setpoints based on a combination of power oscillation period confirmation counts and oscillation amplitude. These setpoints are designed to ensure that the SLMCPR is not violated by the presence of growing power oscillations resulting from anticipated instability events. Option III methodology reliance on a fixed amplitude setpoint, which is associated with the SLMCPR, requires quantification of the MCPR performance as a function of power oscillation scenarios for the full spectrum of core designs and operating conditions.

The DSS-CD methodology is also based on identification and confirmation of power oscillation periods, characteristic of reactor instability. However, the confirmation process in this approach takes place at the threshold of reactor instability. By providing suppression at these conditions, the development of power oscillations that could challenge the SLMCPR is avoided. This early recognition function is performed by the CDA, which identifies the unique features of instability threshold and generates a reactor trip before significant power oscillations and MCPR margin degradation develop.

4.2 APPROACH

The CDA and its associated setpoints are described in Section 3.3.1. The CD and Amplitude Discriminator (AD) setpoints are used by the CDA to protect the SLMCPR from anticipated instability events. These anticipated events exhibit gradual reactor transition from a stable to an unstable configuration. The physical parameters in a reactor that are critical to the coupled thermal-hydraulic and neutronic stability characteristics require a finite time to realign following an anticipated transient that results in power oscillations.

At the instability threshold, although the DR may constantly increase, the power oscillations do not experience a significant amplitude growth because the DR is less than 1.0. Only when the DR exceeds 1.0, following the instability inception, can the oscillation amplitude start to appreciably increase.

The CDA is designed to provide effective early protection of the fuel SLMCPR. No significant MCPR degradation is expected during the short duration between the initial oscillation recognition for the specified CD [[

]] As a result, power oscillations are not permitted to grow significantly above the background neutron noise level.

Significant margin to the SLMCPR is assured at the instability inception, which may be reached as a result of:

a. Normal operational maneuvers, which maintain significant MCPR margin at off-rated conditions,

b. Anticipated events from off-rated conditions, which are expected to be mild and retain substantial MCPR margin, or

c. Anticipated flow reduction events from rated conditions, which are expected to result in a MCPR margin increase from the required margin at the initial rated conditions (i.e., OLMCPR).

As stated above, the transition to fully developed instability is gradual. Therefore, the CDA protection precludes any significant MCPR margin degradation as a result of anticipated instability events. The SLMCPR is protected by generating a reactor scram before the core thermal-hydraulic conditions deviate significantly from steady state conditions. Based on BWR operational experience, the anticipated increase in background neutron noise level at the instability inception is no more than approximately a factor of 3 prior to reactor trip, and therefore has an insignificant effect on MCPR margin.

To confirm the MCPR performance of anticipated instability events, reasonably limiting, best-estimate event simulations are performed using the GEH TRACG code for a specified range of operating conditions, selected GEH BWR product lines, and anticipated oscillation modes. It must be emphasized that these TRACG event simulations are not used to determine the CDA setpoints, nor are they used to establish the SLMCPR. Their sole purpose is to confirm the inherent MCPR margin afforded by the CDA design. Method qualifications and uncertainty treatment are addressed in Reference 19.

4.3 GENERIC APPLICABILITY ENVELOPE

The confirmation process of MCPR performance afforded by the DSS-CD for anticipated instability events is established on a generic basis. To this end, a set of key parameters is identified and a range established to define a generic applicability envelope. Future plant-specific designs, which are bounded by the generic applicability envelope, are confirmed based on the generic basis documented in this report. If any of the key parameters is outside of the generic applicability envelope for plant-specific application, additional justification may be required, as described in Section 6.0. This section addresses TLO considerations. SLO is addressed in Section 4.4.2.

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The specified range established for each of these parameters is summarized in Table 4-1. The plant-specific review process, confirming the continued applicability of the DSS-CD generic applicability envelope, is documented in Section 6.0. The analyses documented in this report, demonstrating the MCPR performance on a generic basis for anticipated core wide and regional mode oscillations, address the specified range of the generic applicability envelope key parameters.

[[

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4.4 SLMCPR PROTECTION CONFIRMATION

The SLMCPR protection confirmation is based on anticipated instability events, which are defined to include core wide and regional modes oscillations with full core participation at reasonably limiting conditions and core designs. These events are initiated as a result of anticipated transients or normal operational maneuvers. All other instability events are considered unanticipated events. They do not require SLMCPR protection and are addressed by the defense-in-depth solution features of DSS-CD. Consistent with the DSS-CD generic confirmation envelope, reasonably limiting events are selected and simulated by TRACG to quantify their effect on the margin to SLMCPR. A generic DSS-CD procedure specifying bounding CPR uncertainty is established and used to confirm that the margin to the SLMCPR for the reasonably limiting best-estimate events is adequate. Section 4.4.1 addresses TLO considerations and Section 4.4.2 addresses SLO.

The purpose of the confirmation analysis event matrix is to evaluate the licensing basis generic applicability envelope (Table 4-1) and any future changes outside this envelope. The events to be considered are identified in the matrices associated with TLO (Table 4-2) and SLO (Table 4-7).

4.4.1 Two Loop Operation

The TLO limiting events, selected to confirm that the SLMCPR is protected by the DSS-CD design, are established based on a review of all potential anticipated instability event initiators. Anticipated instability events may be initiated as a result of:

a. Normal operational maneuvers,

b. Anticipated events from off-rated operating conditions, or

c. Anticipated flow reduction events from rated conditions.

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4.4.1.1 Event Simulation

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The simulation results in the following section are used to assess the MCPR response and margin to the SLMCPR. As an example, the transient responses of key simulation parameters, including core power and flow, core inlet subcooling, hot channel power, hot channel flow, leading OPRM cell normalized signal and CPR, are presented in [[

]] The event suppression occurs prior to any significant amplitude growth and CPR degradation, as discussed in the next section.

4.4.1.2 MCPR Performance

The margin to the SLMCPR for each of the TRACG simulated events is calculated by applying the DSS-CD evaluation methodology to the event MCPR results. The evaluation methodology and the event specific MCPR margin results are discussed in the following subsections.

Evaluation Methodology

The DSS-CD evaluation methodology establishes the time sequence from the oscillation detection through suppression, and determines the SLMCPR margin from the TRACG generated MCPR results. The TRACG simulations represent best-estimate calculations for reasonably limiting instability scenarios. A CSAU assessment is provided in Reference 19.

The DSS-CD evaluation methodology represents a significant simplification from the Option III licensing methodology. [[

]]

The elimination of these elements is possible because of the:

a. Early detection and suppression of oscillations afforded by the CDA,

b. Elimination of determining the amplitude setpoint directly based on SLMCPR protection (i.e., the final MCPR is equal or just above the SLMCPR) in the licensing basis detection algorithm, and

c. Use of TRACG to simulate the full instability scenario, from the steady state initial condition to the instability suppression.

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Best Estimate MCPR Margin

The DSS-CD evaluation methodology has been applied to the cases specified in the confirmation analysis event matrix (Table 4-2). Table 4-4 summarizes the nominal MCPR performance and margins to the SLMCPR for these cases for [[

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For all cases in Table 4-4, adequate margin to the SLMCPR is maintained. [[

]] and therefore confirms on a generic basis the CDA early detection capability and the CDA setpoints selection.

MCPR Uncertainty Assessment

A practical yet conservative approach is selected to establish the MCPR uncertainty resulting from the best-estimate TRACG results. This approach was confirmed using the CSAU approach described in Reference 19.

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]] For each of these cases the final MCPR, including the DSS-CD procedure component uncertainties, and the resulting SLMCPR margin are summarized in Table 4-5. For all cases, adequate margin exists, confirming the DSS-CD protection approach and setpoint selection. [[

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4.4.2 Single Loop Operation

[[

]] and therefore confirms on a generic basis the CDA early detection capability and the CDA setpoints selection for SLO.

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]] The final MCPR, including the DSS-CD procedure component uncertainties, and the resulting SLMCPR margin are summarized in Table 4-10, demonstrating adequate margin and confirming the DSS-CD protection approach and setpoint selection for SLO.

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4.5 SOLUTION ARMED REGION

The DSS-CD solution is designed to reliably and readily detect and suppress both core wide and regional mode oscillations prior to violating the SLMCPR for anticipated oscillations. The ability to trip the reactor and generate system alarm is automatically enabled at power and flow conditions potentially susceptible to power oscillation. The trip-enabled region is termed the Armed Region. For DSS-CD, the Armed Region boundaries are specified on a generic basis to envelop power and flow conditions potentially susceptible to power oscillation.

The trip and alarm functions are automatically enabled below a specified flow level and above a specified core power level. The DSS-CD Armed Region is illustrated in Figure 4-20. The specified flow level is designed to disarm the trip and alarm functions during rated power operations. Because power oscillations are not expected at rated power operations and the reactor is operated at these conditions most of the time, disarming the trip and alarm functions reduces the probability of unnecessary spurious scrams. In addition, the specified flow level is designed to arm the trip and alarm functions at a flow level that bounds the core conditions potentially susceptible to power oscillation.

To accomplish these goals, the flow level is set just below the minimum flow associated with rated power operation. The flow boundary of the Armed Region is generically specified as 75% of rated recirculation drive flow for plants licensed for MELLLA+ operations and 70% of rated recirculation drive flow for plants not licensed for MELLLA+ operations. The flow signal used to implement the Armed Region is the relative recirculation drive flow. The relative recirculation drive flow at the 100% core power and 100% core flow statepoint is defined as the rated recirculation drive flow. Because the relationship between the core flow and recirculation drive flow has a weak dependence on core power, small variation in the Armed Region flow boundary in terms of core flow may be observed during operation as a function of the core power level (or load line). However, this is acceptable because the resulting effect of slight variation in the Armed Region boundary in terms of core flow has a negligible effect on stability margin based on the low DRs around the Armed Region boundary as demonstrated in Table 4-12.

The specified power level is designed to arm the trip and alarm functions at a power level that bounds the core conditions potentially susceptible to anticipated power oscillations. This power level is selected generically at the MCPR monitoring threshold of 25% OLTP. For a power-uprated plant, the MCPR monitoring threshold may have been scaled to a lower percent value. This scaled value defines the Armed Region boundary in this situation. Instabilities are not expected to occur below 30% OLTP. In the unlikely event of significant stability margin degradation at this power level, the loss of margin is gradual, allowing for early detection by the system. In addition, below the MCPR monitoring threshold, an instability event would not be expected to grow large enough to threaten the SLMCPR. This expectation is due, in part, to the large MCPR margin that exists at low power operation.

To demonstrate that the generic Armed Region boundaries are associated with stable core conditions, ODYSY (Reference 6) calculations were performed for reasonably limiting conditions on the boundaries of example BWR/4 and BWR/6 plants for both MELLLA+ and pre-MELLLA+ operating domains. Table 4-12 summarizes the state point conditions and calculated DR results. [[

]] As expected, both channel and core DRs are low, indicating weak susceptibility to both core wide and regional oscillations at or near the Armed Region boundaries.

4.6 APPLICATION TO NON-GEH/GNF FUEL DESIGN

The fuel design range of applicability of this report is specified in Tables 4-1 and 4-6. Fuel designs not covered in this report, including non-GEH/Global Nuclear Fuel (GNF) fuel, are addressed as outlined in Section 6.0. This report methodology, or equivalent NRC approved methodology, will be used to confirm adequate MCPR performance of the new fuel design. Application of this report MCPR confirmation methodology to existing non-GEH/GNF fuel design is expected to result in confirmation of adequate MCPR margins because of the fuel design thermal-hydraulic compatibility and the robustness of the DSS-CD solution.

4.7 LICENSING BASIS FOR HIGHER S_{AD} SETTINGS

Section 4.4 demonstrated on a generic basis that the DSS-CD system and its associated setpoints result in timely suppression of oscillations with adequate margin to the SLMCPR for anticipated instability events. To confirm the MCPR performance of anticipated instability events, reasonably limiting, best-estimate event simulations were performed using the GEH TRACG code for a specified range of operating conditions, selected GEH BWR product lines, and anticipated oscillation modes. These TRACG event simulations were not used to determine the CDA setpoints, nor were they used to establish the SLMCPR. Their sole purpose was to confirm the inherent MCPR margin afforded by the CDA design.

4.7.1 S_{AD} Settings and Requirements

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4.7.2 Process for DSS-CD Application

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4.7.3 Example of DSS-CD Application

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Note: 'RS' in the figure above is a normalized signal without units. Figure 4-9 depicts [[

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Therefore, 'C_n' in Figure 4-9 is the same as 'RS' in the figure above, a normalized signal without units.

[[

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Table 4-1 TLO DSS-CD Licensing Basis Generic Applicability Envelope

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Table 4-2 TLO TRACG Confirmation Analysis Event Matrix

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Table 4-3 TLO DSS-CD Evaluation Methodology Summary

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Table 4-4 TLO Nominal TRACG Confirmation Analysis MCPR Performance

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Table 4-5 TLO DSS-CD Bounding TRACG MCPR Margin

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Table 4-6 SLO DSS-CD Licensing Basis Generic Applicability Envelope

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Table 4-7 SLO TRACG Confirmation Analysis Event Matrix

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Table 4-8 SLO DSS-CD Evaluation Methodology Summary

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Table 4-9 SLO Nominal TRACG Confirmation Analysis MCPR Performance

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Table 4-10 SLO DSS-CD Bounding TRACG MCPR Margin

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Table 4-11 Trip Times for TRACG Confirmation Analysis

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Table 4-12 ODYSY Confirmation of the Armed Region Boundaries

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Table 4-13 [[ ]]

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Table 4-14 [[

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Table 4-15 [[ ]]

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Table 4-16 [[ ]]

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Table 4-17 [[ ]]

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Figure 4-1 [[ ]]

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Figure 4-2 [[ ]]

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Figure 4-3 [[ ]]

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Figure 4-4 [[ ]]

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Figure 4-5 [[ ]]

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Figure 4-6 [[ ]]

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Figure 4-7 [[ ]]

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Figure 4-8 Full Core Individual Bundle Model for BWR/6 TRACG 2RPT Instability Event

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Figure 4-9 [[ ]]

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Figure 4-10 [[ ]]

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Figure 4-11 [[ ]]

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Figure 4-12 [[ ]]

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Figure 4-13 [[ ]]

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Figure 4-17 [[ ]]

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Figure 4-18 [[ ]]

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Figure 4-19 [[ ]]

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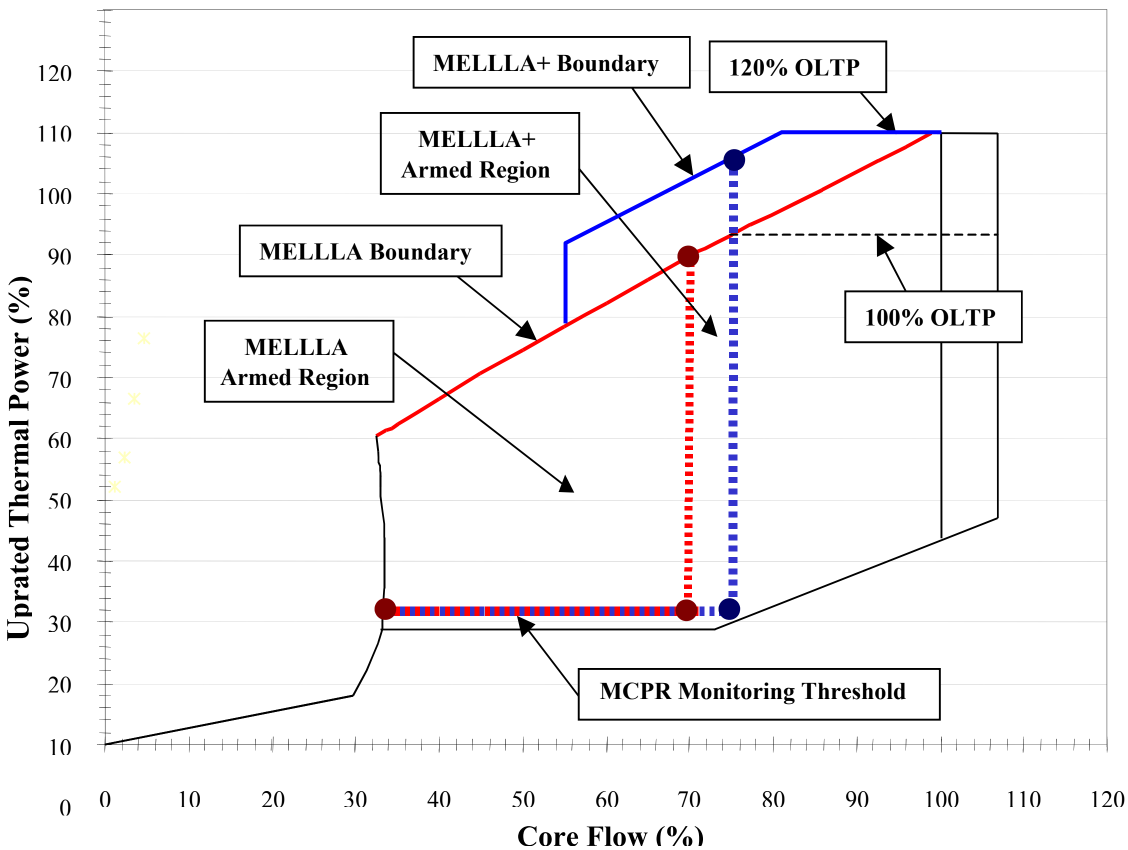
Figure 4-20 DSS-CD Armed Region Illustration
(100% EPU = 120% OLTP)



Note: The Armed Region flow boundary is defined and implemented by the recirculation drive flow and is shown as an approximate vertical line as a function of core flow for illustration purposes only.

5.0 SOLUTION QUALIFICATIONS AND UNCERTAINTIES

5.1 TRACG APPLICATION

The TRACG code is used to simulate [[ ]] events to confirm the DSS-CD solution early oscillation detection and suppression capability. The TRACG event simulations are not used to establish the DSS-CD CDA design or setpoints. The TRACG application to DSS-CD is documented in Reference 19.

5.1.1 TRACG Qualifications

TRACG is a GEH proprietary version of the Transient Reactor Analysis Code (TRAC). TRACG uses advanced best-estimate one-dimensional (1-D) and 3-D methods to model the phenomena that are important in evaluating the operation of BWRs. Best-estimate analyses performed with TRACG have been approved by the NRC to support licensing applications in different areas, including specific thermal-hydraulic instability performance and Anticipated Operational Occurrence (AOO) transients (Reference 7). The TRACG qualification review to provide background for the code limited use in support of the DSS-CD application is documented in Reference 19.

5.2 CSAU METHODOLOGY APPLICATION

Compliance with the CSAU methodology (References 10 and 11) of TRACG for DSS-CD applications is documented in Reference 19. [[

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5.3 DETECTION ALGORITHM TESTING

The DSS-CD licensing basis detection algorithm, the CDA, relies on the recognition of successive periods in OPRM cells signals that consists of two related pattern recognition elements:

a. Successive period detection, and

b. CD recognition.

Actual plant data and TRACG event simulations that are used to test these CDA elements are documented in this section.

5.3.1 Successive Period Detection

The PBA application in DSS-CD for the purpose of recognizing successive oscillation periods is similar to Option III. The key PBA testing from References 1 and 2 is summarized in Table 5-1. Testing of the PBA application to OPRM cells was performed in support of Option III algorithm qualifications and is also summarized in Table 5-1.

Because certain changes are introduced to the PBA for application to the CDA, selected retesting is appropriate. The PBA modifications and restrictions specified in Section 3.4.1.1 are expected to have insignificant effect on the testing and qualifications documented in References 1 and 2. [[

]] Table 5-1 lists the retested plant data, which includes Pilgrim stable startup data and Kernkraftwerk Leibstadt (KKL) instability event data. These retests have demonstrated that the PBA changes have insignificant effect on the detection results, as expected.

The PBA was applied to selected TRACG power traces to test the algorithm capability to recognize the inception of instability [[ ]] The PBA, consistent with the modifications and restrictions specified in Section 3.4.1.1, provided timely identification of the inception of instability oscillations and continuous recognition of successive period counts. [[

]]

5.3.2 Confirmation Density Recognition

The CDA requires simultaneous successive counts of multiple OPRM cells for generating an OPRM channel trip signal. The testing of the instability events listed in Table 5-1 were previously performed for multiple LPRMs. However, the relative timing of the successive period counts is not included in Reference 2. To demonstrate the CD approach and effectiveness, multiple LPRM signals from the KKL Cycle 7 regional instability test event and Columbia Cycle 8 core wide instability event were examined by the PBA, integrated to calculate the CD as function of time, and compared to the algorithm CD setpoint. A summary of CDA testing against plant data is provided in Table 5-2.

A segment of the KKL Cycle 7 regional instability test, STAB5, was selected to demonstrate the CDA performance. This test segment is at the instability threshold and exhibits very gradual loss of stability margin. The PBA was applied to the available 25 LPRM signals that were recorded during the test. Figure 5-1 illustrates the stability performance of two LPRMs, including signal amplitude and PBA SCC. The LPRMs were selected to represent examples of responsive and unresponsive signals. Figure 5-2 depicts the CD based on the single LPRM PBA confirmation results. The figure illustrates the CDA responsiveness and ability to identify the instability inception and generate a trip signal when the CD setpoint [[ ]] is reached. The number and distribution of the LPRMs was not conducive for OPRM cell demonstration. OPRM cell demonstration is performed for the Columbia instability event below.

The KKL Cycle 7 regional instability test represents a significant challenge for the CDA demonstration. The oscillations were established under controlled test conditions and resulted in a very gradual instability inception. The test was also occasionally interrupted by manual operator actions (e.g., control rod movements). In addition, the test appears to exhibit precession characteristics during its instability inception. For instabilities resulting from anticipated events [[ ]] with no manual operator manipulations, full core coupling and distinct characteristic oscillatory behavior is expected to form early in the event.

The second CDA demonstration example consists of the Columbia Cycle 8 unplanned instability event. The PBA was applied to the available 80 LPRM signals that were recorded during the event. These LPRMs consist of LPRM levels A and C (i.e., bottom and third from bottom axial positions). They were divided into 2 representative RPS channels of 39 LPRMs (Channel 1) and 41 LPRMs (Channel 2), as illustrated in Figure 5-3. The figure also illustrates an OPRM cell assignment, which simulates 2 OPRM channels of 35 OPRM cells each. This OPRM cell assignment is similar to the Columbia's assignment, including adjustments to accommodate the available recorded LPRM signals. Most of the OPRM cells consist of 4 LPRMs and only a few with a lesser count.

Figure 5-4 illustrates the stability performance of a typical LPRM signal, including signal amplitude and PBA SCC. [[

]] which is initiated prior to any significant signal amplitude growth. The figure also includes a simulated OPRM cell signal, associated with the selected LPRM. It compares the performance of a 4-LPRM OPRM cell to one of its LPRM signals. [[

]]

Figure 5-5 depicts the CD based on a single LPRM per OPRM cell PBA confirmation results. The figure illustrates the CDA ability to identify the instability inception and generate an early trip signal when the CD setpoint [[ ]] is reached. Even though the event is developing slowly with a low growth rate, the increase in the number of confirming LPRMs is apparent. The figure demonstrates that the CD is not increasing prior to the development of oscillatory behavior, is associated with the instability threshold, and is rapidly increasing as the instability event develops.

The Columbia Cycle 8 instability event was also used to test the CDA detection capability with OPRM cells consisting of multiple LPRMs, as illustrated in Figure 5-3. Figure 5-6 depicts the OPRM CD performance, including the LPRM based CD for comparison. [[

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as indicated in the figure. [[

]].

Figure 5-6 illustrates the effectiveness of the OPRM approach. The simulated OPRM channels exhibit a total number of confirming cells that is continuously increasing as the event evolves, reaching a CD close to unity when the oscillation amplitude has not shown any significant growth (around 50 seconds). This test demonstrates the CDA capability to provide early detection and suppression signal. In addition, it successfully demonstrates the use of OPRM cells as the source of signal to the CDA.

In addition, the CDA was applied to selected TRACG power traces in Section 4.0, which demonstrated the algorithm capability to recognize the instability inception [[

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5.4 SETPOINT METHODOLOGY APPLICABILITY

The DSS-CD relies on several setpoints for its oscillation detection algorithms. These setpoints are classified into three distinct groups:

a. CDA setpoints,

b. Defense-in-depth algorithms setpoints, and

c. Armed region setpoints.

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5.4.1 CDA Setpoints

The CDA includes trip and alarm setpoints, which are assigned discrete values. They include the successive confirmation count threshold (N_{Th}), amplitude discriminator setpoint (S_{AD}), CDA alarm setpoints (N_{Al} and S_{AA}), and confirmation density setpoint (S^{j}_{CD}).

N_{Th} is a generic, predetermined discrete setpoint [[ ]]. Its purpose is to provide early recognition of OPRM cell oscillatory behavior. For a well-developed oscillatory behavior at the instability threshold and inception, the successive period count is an unambiguous process. In addition, based on actual experience and simulation of instability events, N_{Th} is selected well below the count range associated with SLMCPR violation.

The CDA utilizes the amplitude discriminator setpoint (S_{AD}) to prevent CDA-generated trip signals at the naturally occurring OPRM signal noise level. The choice of S_{AD} is based on two considerations. [[

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The alarm SCCs and amplitude setpoints, N_{Al} and S_{AA}, respectively, are selected on a plant and cycle-specific basis and are based on plant-specific operational objectives and preferences. The alarm setpoints (S_{AA} and N_{Al}) are a non-licensing basis features added to provide a meaningful alarm to the operators and to limit the occurrence of nuisance alarms.

S^{j}_{CD} is used to generate a trip signal based on a limited number of OPRM cells exhibiting oscillatory behavior. For a well-developed oscillatory behavior at the instability threshold and inception, the count of confirming OPRM cells, recognized by the CDA, is a discrete and unambiguous process. In addition, based on actual experience and simulation of instability events, S^{j}_{CD} is selected well below the count range associated with SLMCPR violation.

5.4.2 Defense-in-Depth Setpoints

The defense-in-depth algorithms are based on a generic set of nominal setpoint values, summarized in Table 3-2. The defense-in-depth algorithms are not designed to provide SLMCPR protection.

5.4.3 Armed Region Setpoints

The DSS-CD Armed Region is defined to conservatively bound the operating domain region potentially susceptible to core oscillations. The bounding size of the region is designed to accommodate, on a generic basis, all plant-specific applications within the solution licensing basis generic applicability envelope defined in Tables 4-1 and 4-6. Confirmatory analysis of the DRs at the Armed Region boundaries demonstrated large stability margin. Significant instability events are expected only at low core flow and high core power conditions. Operations at lower core power or higher core flow, well within the Armed Region (i.e., approximately 60% core flow, 30% OLTP), may result in a gradual loss of stability margin. For these conditions, early indication of degraded stability margin is available through the alarm feature of the solution. [[

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Table 5-1 Summary of PBA Testing against Actual Plant Data

Testing Purpose	Data Source	Reference	Retest
Single/Multiple LPRM count response for operational event	LaSalle pump upshift event	2	No
Single/Multiple LPRM count response for stable steady state conditions	Pilgrim stable startup data	2	Yes
Single/Multiple LPRM count response for operational events	Limerick test data (1RPT, 2RPT, turbine stop valve, pressure regulator, feedwater flow step change, recirculation flow step)	2	No
Single/Multiple LPRM count response for regional instability event	KKL Cycle 1 instability events	2	No
Single/Multiple LPRM count response for regional instability event	KKL Cycle 7 instability events	2	Yes
Single/Multiple LPRM count response for regional instability event	Caorso instability data (regional)	2	No
OPRM count response for regional instability event	KKL Cycle 7 instability events	2	Yes
OPRM count response for core wide instability event	Limerick Cycle 1	2	No

Table 5-2 Summary of CDA Testing against Actual Plant Data

Testing Purpose	Data Source
Multiple LPRM count response and timing for regional instability test event	KKL Cycle 7 instability event (STAB5)
Multiple LPRM and OPRM count response and timing for core wide instability event	Columbia Cycle 8 instability event

Figure 5-1 Example LPRMs Performance for KKL Cycle 7 Instability Test (STAB5)

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Figure 5-2 CD Performance for KKL Cycle 7 Instability Test (STAB5)

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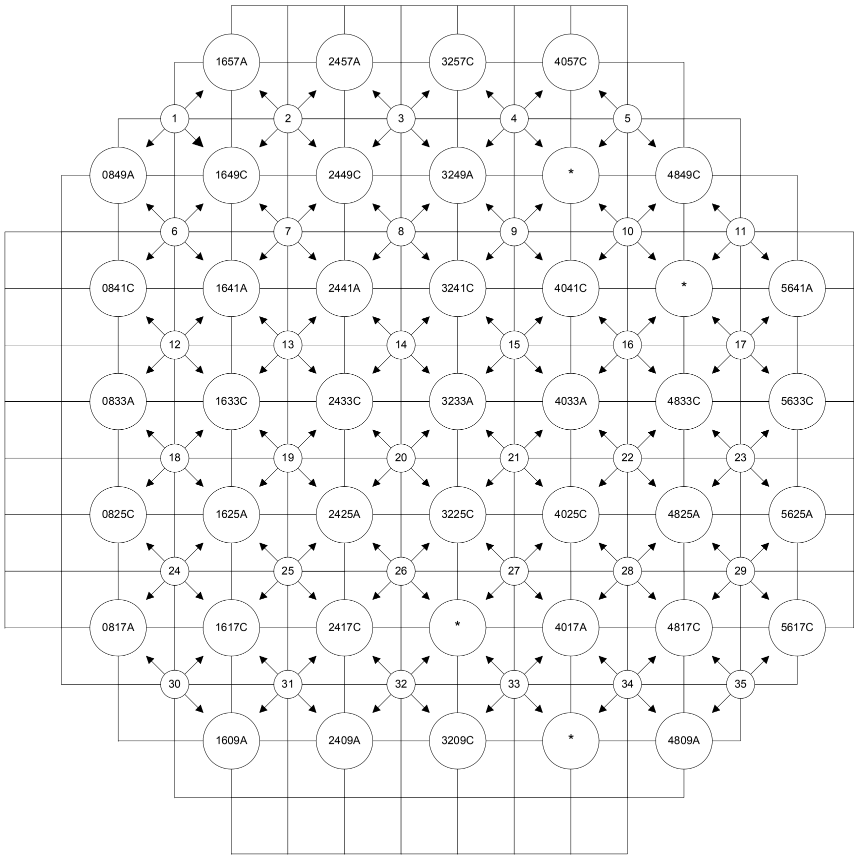
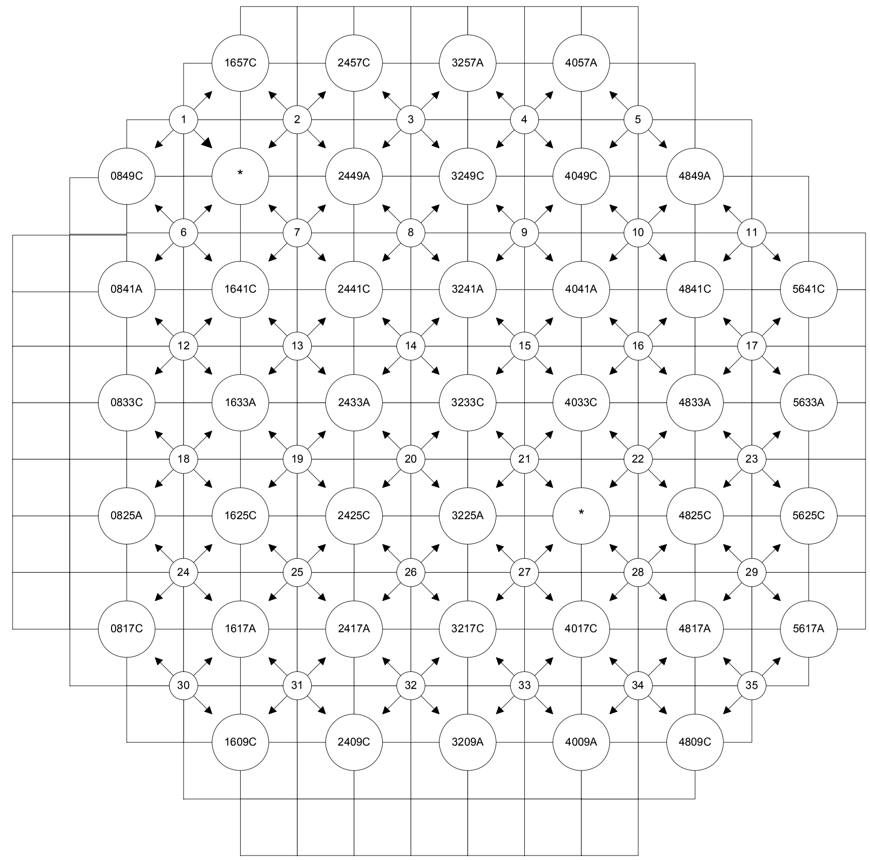
Figure 5-3 Columbia LPRM/OPRM Assignment Map Demonstration



*Data not available

764 Bundle Core, OPRM Channel 1



*Data not available

764 Bundle Core, OPRM Channel 2

Figure 5-4 Example LPRM/OPRM Performance for Columbia Cycle 8 Instability Event

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Figure 5-5 LPRM CD Performance for Columbia Cycle 8 Instability Event

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Figure 5-6 OPRM CD Performance for Columbia Cycle 8 Instability Event

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6.0 PLANT-SPECIFIC APPLICATION

A plant-specific review procedure is established to confirm that the generic DSS-CD licensing basis is applicable to plant-specific designs, including reload designs, and therefore, demonstrating SLMCPR protection by the DSS-CD for anticipated stability related oscillations. If the generic DSS-CD licensing basis is not applicable (NA) to a plant-specific design, additional analyses will be necessary to demonstrate applicability.

6.1 PLANT-SPECIFIC REVIEW PROCESS

The generic DSS-CD licensing basis allows solution implementation for GE BWR/3-6 product lines and existing GEH/GNF fuel designs. The solution provides for early instability detection and suppression with minimal degradation in CPR performance during anticipated instability events. The resulting inherent CPR margin to the SLMCPR is expected to accommodate future evolution in fuel cycle designs and operating flexibility features that may affect stability performance.

The standard plant-specific review process, which also applies to the reload process, consists of an applicability checklist, confirming that the generic applicability envelope, as defined in Section 4.0, is not exceeded. The plant-specific applicability checklist is provided in Table 6-1 for TLO and in Table 6-2 for SLO. [[

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If any checklist criterion is not met as a result of a plant-specific design change that may affect reactor stability performance, the DSS-CD plant-specific procedure will be performed to demonstrate adequate SLMCPR protection. If the design change is either within the DSS-CD plant-specific applicability checklist envelope or does not affect the reactor stability performance, no additional DSS-CD applicability demonstration analysis is required.

Any extension of the DSS-CD applicability envelope requires confirmation analysis based on the methodology outlined in Section 4.0. In Section 4.0, the [[

]] The DSS-CD procedure uncertainty (or equivalent), documented in Section 4.0, is then applied to confirm the margin to the SLMCPR. The DSS-CD applicability extension procedure is summarized in Table 6-3 for TLO and in Table 6-4 for SLO.

Design changes beyond the DSS-CD plant-specific applicability checklist envelope that affect stability performance will require confirmation analysis according to the DSS-CD applicability extension procedures of Tables 6-3 and 6-4. [[

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If the DSS-CD applicability extension involves a new GEH/GNF fuel design beyond GE14 or non-GEH/GNF fuel designs, then Table 6-5 is applied. The table lists the possible fuel design transitions among approved and unapproved GEH/GNF (UGE) and non-GEH/GNF fuel designs for DSS-CD applications. The table specifies the required [[

]] This process would apply to both cases where a new fuel design product line such as GNF2 loaded core is implementing DSS-CD and where a DSS-CD core is introducing a new fuel design product line such as GNF2 fuel. Both of these scenarios are described in Reference 23. [[

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6.2 LEAD USE ASSEMBLY

For a typical reload core, single channel oscillations are not probable because unstable channel condition is approached by a large number of channels, leading to significant core participation in the ensuing instability. However, the introduction of lead use assemblies (LUAs) in a reload core creates the possibility of a unique thermal-hydraulic behavior, potentially leading to single channel oscillations. The DSS-CD solution provides early detection for such situations through its alarm function and eventual trip signal in the event of significant oscillation magnitude through its defense-in-depth protection features. When a limited number of LUAs is introduced to a reload core, the LUA thermal-hydraulic performance and stability characteristics will be assessed to determine potential susceptibility to single channel oscillations.

Table 6-1 TLO DSS-CD Plant-Specific Applicability Checklist

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Table 6-2 SLO DSS-CD Plant-Specific Applicability Checklist

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Table 6-3 TLO DSS-CD Applicability Extension Evaluation Procedure

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Table 6-4 SLO DSS-CD Applicability Extension Evaluation Procedure

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Table 6-5 Required TRACG Cases for Fuel Design Transition Scenarios

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7.0 BACKUP STABILITY PROTECTION

7.1 INTRODUCTION

This section provides a description of BSP approaches that may be used when the OPRM system is inoperable, applicable up to and including operation in the MELLLA+ domain. The elements of the BSP are confirmed on a plant and cycle specific basis to provide consistency with the LTS general requirement of long-term applicability. Other NRC approved backup approaches that are justified to provide appropriate protection may also be implemented.

Two BSP options are presented in this section and summarized in Section 7.5. Both options provide adequate protection for continued operation in the unlikely event the DSS-CD licensing basis algorithm cannot be demonstrated to provide its intended SLMCPR protection. The sections below discuss the three constituents of the two options, which are:

Manual BSP Regions	Comprises plant-specific regions (Scram and Controlled Entry) in the licensed power-flow operating domain and specified manual operator actions. The basis for the Manual BSP Regions is presented in Section 7.2, Manual BSP Region Boundaries Generation
BSP Boundary	Defines the operation domain where potential instability events can be effectively addressed by specified operator actions. Its basis is presented in Section 7.3, BSP Boundary Generation
Automated BSP Scram Region	Comprises an automatic reactor scram region implemented by the APRM flow-biased scram setpoint. Its basis is presented in Section 7.4, Automated BSP Scram Region Generation

7.2 MANUAL BSP REGION BOUNDARIES GENERATION

The DSS-CD Manual BSP Regions use the GE/BWROG Interim Corrective Actions (ICAs) regions presented in Reference 5 as a starting point. The following elements are included in the Manual BSP Region generation process:

- The size of the base (minimal) Manual BSP Regions is equivalent to the current ICA regions,

- The three ICA regions (Scram, Exit, Controlled Entry) are replaced by two Manual BSP Regions (Scram and Controlled Entry),
- Common DR criteria are established for plant and cycle-specific confirmation, and as necessary, the base Manual BSP Regions are increased to satisfy these criteria,
- The Manual BSP Regions are established based on two intercept state points, one on the High Flow Control Line (HFCL) and the other on the Natural Circulation Line (NCL), which are connected by a BSF. When confirming the Manual BSP Regions for MELLLA+ operation, the HFCL is defined as the MELLLA+ upper boundary above 55% core flow and its extension to the NCL. The NCL is defined as the plant-specific NCL,
- The manual BSP regions is developed considering the appropriate feedwater temperature, including reduced feedwater temperature operation,
- Operator actions in the two Manual BSP Regions are similar to the operator actions currently defined for the ICA Scram and Controlled Entry regions,
- Operator awareness is required when operating within 10% of rated core flow or power (Operator Awareness Region) from the Manual BSP Controlled Entry region.

Figure 7-1 illustrates the base Manual BSP Regions relative to the ICA regions. For uprated plants, the ICA region boundaries are scaled to maintain the pre-uprate region boundaries absolute power and flow values, which is then used to generate the base Manual BSP Regions, following the process illustrated in Figure 7-1.

7.2.1 Boundary Shape Function

The BSP application procedure defines state points on the HFCL and the NCL that meet the region boundary generation stability criteria. The region boundary is then defined with a shape function. The shape function is a fit to the power/flow state points with all points along the boundary line representing a constant DR. Two BSFs are defined:

(1) Generic Shape Function (GSF)

(2) MSF

7.2.1.1 GSF

The GSF is a conservative fit to power/flow state points representing a constant DR. The GSF procedure is applied to two state points that meet specified region boundary generation stability criteria, one on the HFCL and the other on the NCL. The region boundary is defined with the GSF as:

$$P = P_B \left(\frac{P_A}{P_B} \right)^{\frac{1}{2}\left[\frac{W - W_B}{W_A - W_B} + \left(\frac{W - W_B}{W_A - W_B} \right)^2 \right]}, \qquad W \geq W_B$$

where:

Point A: Intersection of the HFCL and specified core flow

Point B: Intersection of the NCL and specified load line

P: Core power in % rated

W: Core flow in % rated.

If core flow rates below W_B are assessed, the GSF slope may become negative when the quadratic exponential term dominates. Typically, this situation is not expected to occur because the flow range below W_B is limited. In the unlikely situation where negative slope below W_B is encountered, a modified form of this function is used. To ensure both a positive slope and continuity below W_B, the quadratic exponential term is eliminated and the following function is used:

$$P = P_B \left(\frac{P_A}{P_B} \right)^{\frac{1}{2}\left[\frac{W - W_B}{W_A - W_B} \right]}, \qquad W < W_B$$

7.2.1.2 MSF

The MSF is an alternative to the GSF to fit power/flow state points representing a constant DR. The MSF is defined by the following equation:

$$P = P_B \left(\frac{P_A}{P_B} \right)^{\left[\frac{W - W_B}{W_A - W_B} \right]}$$

where:

Point A: Intersection of the HFCL and specified core flow

Point B: Intersection of the NCL and specified load line

P: Core power in % rated

W: Core flow in % rated

Because the MSF produces a flatter region boundary, a validation analysis is performed every cycle for reload licensing applications to confirm that the stability criteria are satisfied. Validation calculations are performed to demonstrate that all power/flow points along the boundary will produce a DR that is the same or lower than the DRs of the power/flow state points on the HFCL and the NCL. This validates that the application of the MSF produces a conservative region boundary.

The application of either region BSF provides conservative regions for stability solutions. A comparison of the Exclusion Region (ER) established by the MSF and GSF to a line of constant DRs determined by ODYSY is shown in Figure 2-1 of Reference 6, which demonstrates that both shape functions result in conservative stability regions.

The MSF is a shared element that is also applied to the Option 1-D, Option II, and Option III LTS and has been approved in Reference 6. The addition of the MSF for the calculations of the stability region boundaries drives consistency with the application of BSP and ER methodologies for stability Option I-D, Option II, and Option III solutions. It also eliminates a possible inconsistency for a non-M+ plant implementing DSS-CD Solution to replace Option I-D, Option II, or Option III solutions.

7.2.2 Base Manual BSP Regions Derivation

The base Manual BSP Regions are generated based on the minimal requirements of the original ICA regions using a BSF (as illustrated in Figure 7-1 for the GSF). The base Manual BSP Regions are established on a plant-specific basis based on the generic process outlined below.

The base Manual Scram Region (Region I) boundary is generated by applying a BSF to Points A and B:

Point A: Intersection of the MELLLA upper boundary and 40% rated core flow

Point B: Intersection of the NCL and 100% OLTP load line

The base Manual BSP Region I boundary is extrapolated up to the extension of the MELLLA+ HFCL through the application of a BSF for core flows above 40%.

The base Manual BSP Controlled Entry Region (Region II) boundary is generated by applying a BSF to Points A' and B':

Point A': Intersection of the MELLLA upper boundary and 50% rated core flow

Point B': Intersection of the NCL and 70% OLTP load line

The base Manual BSP Region II boundary is defined only up to the MELLLA upper boundary.

The base manual BSP regions for MELLLA+ operation are illustrated in Figure 7-2 and the base manual BSP region boundaries define the minimum region size required.

7.2.3 Manual BSP Regions Plant-Specific Application

The process defining the plant and cycle-specific manual regions is described in this section.

7.2.3.1 Region I – Manual BSP Scram Region

Region Definition

The Manual BSP Region I boundary is established by applying a BSF to Points A (along the HFCL) and Point B (along the NCL). Each point is selected based on the more limiting of the following options:

1. The base minimal region.
2. A best-estimate stability calculation using the ODYSY frequency domain code (Reference 6) with the calculation procedure outlined in Table 7-1 for Manual BSP Region I and the stability criterion associated with 0.8 core and channel DRs, as illustrated in Figure 7-3.

If the best-estimate calculation results at both points are bounded by the base minimal region, the base minimal region is confirmed. If the best-estimate calculation results exceed the base minimal region at any point, the base minimal region is extended at that point.

For MELLLA+, the Manual BSP Region I boundary is extended outside the operating domain upper boundary (i.e., MELLLA) up to the extension of the HFCL, to ensure proper operator action upon unplanned entry into the region. Figure 7-4 illustrates the process for establishing manual BSP boundaries for an example BWR/6. For this example the continued applicability of the base Manual BSP Region I is confirmed.

Actions

An immediate manual scram is required upon determination that the region has been entered. If entry is unavoidable, early scram initiation is appropriate.

7.2.3.2 Region II – Controlled Entry Region

Region Definition

The Manual BSP Region II boundary is established by applying a BSF to Points A' (along the HFCL) and Point B' (along the NCL). Each point is selected based on the more limiting of the following options:

1. The base minimal region.
2. A best-estimate stability calculation using the ODYSY frequency domain code (Reference 6) with the calculation procedure outlined in Table 7-1 for Manual BSP Region II and the stability criterion associated with 0.8 core and channel DRs (illustrated in Figure 7-3) applied to point B' and the stability criterion associated with 0.8 core and channel DRs (also illustrated in Figure 7-3) applied to point A'.

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If the best-estimate calculation results at both points are bounded by the base manual BSP minimal region, the base manual BSP region is confirmed. If the best-estimate calculation results exceed the base manual BSP minimal region at any point, the base manual BSP region is extended at that point.

The Manual BSP Region II boundary is defined by a BSF inside the licensed operating domain. Unlike the Manual BSP Region I boundary, extension of Manual BSP Region II boundary outside the MELLLA upper boundary for the core flow range below the MELLLA+ operating domain extension is not necessary. This is because immediate corrective operator action is required for unplanned operations at reactor power levels exceeding the licensed values. Figure 7-4 illustrates the process for establishing BSP boundaries for an example BWR/6. For this example the continued applicability of the base Region II is confirmed.

Actions

- If the entry is inadvertent or forced, immediate exit from the region is required. The region can be exited by control rod insertion or core flow increase by pump speed increase for MG set plants or FCV opening for FCV plants. Increasing the core flow by either restarting or upshifting (for FCV plants) a recirculation pump is not an acceptable method of exiting the region.
- Deliberate entry into the Manual BSP Controlled Entry Region requires compliance with at least one of the stability controls outlined below:

    - Maintain core average Boiling Boundary (BB) ≥ 4.0 feet,
    - Maintain core DR < 0.6 as calculated by an on-line core stability monitor,
    - Determine appropriate limits for core DR (< 0.60) as calculated by a core stability monitor or by pre-analysis of a reactor state trajectory through the Manual BSP Controlled Entry Region, or
    - Continuous dedicated monitoring of real time control room neutron monitoring instrumentation with manual scram required upon indication of a reactor instability induced power oscillation.

- The guidance and actions recommended by the BSP emphasize instability prevention to minimize the burden placed on the operator when monitoring for the onset of power oscillations. Therefore, caution is required whenever operating near the Manual BSP Region II boundary (i.e., within approximately 10% of core power or core flow), and it is recommended that the amount of time spent operating near this Operator Awareness Region be minimized.

7.3 BSP Boundary Generation

The BSP Boundary delineates that portion of the core power and flow operating domain that is not expected to be susceptible to instability events associated with a high initial growth rate. These instability events if developed can be recognized by the operator sufficiently early to allow timely manual power suppression prior to significant MCPR degradation. [[

]] Therefore, as a conservative measure, operation in MELLLA+ above the BSP Boundary is not permitted.

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7.3.1 BSP Boundary Plant-Specific Application

Boundary Definition

The BSP Boundary is defined by connecting calculated Point A" (at power condition) and calculated Point B" (along the NCL) as illustrated in Figure 7-5. [[

]] This is illustrated in the example BSP Boundaries provided below.

Figure 7-5 illustrates a BSP Boundary for an example BWR/6. [[

]] any flow reduction event from off-rated conditions that is terminated inside the Manual BSP Region I, including all events terminating above the OLTP 100% load line, requires immediate operator action to manually scram the reactor.

Only those portions of the BSP Boundary that traverse the core power and flow licensed operating domain outside the Manual BSP Scram Region are explicitly identified on the operating map. The Manual BSP Controlled Entry Region boundary is extended to the appropriate licensed operating domain upper boundary. If any portion of the BSP Boundary traverses the Manual BSP Scram Region, this portion is not explicitly identified because operation inside the Manual BSP Scram Region requires an immediate action to scram the reactor, which is controlling.

Figures 7-6 through 7-8 illustrate BSP Boundaries for additional examples, comprising of different BWR/4 plants. [[

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Table 7-3 provides a summary of the four BSP Boundary examples. [[

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Actions

Operation above the BSP Boundary requires immediate initiation of actions to lower the reactor power to below the BSP Boundary by control rod insertion.

7.4 AUTOMATED BSP SCRAM REGION GENERATION

The Manual BSP Scram Region, which requires an immediate manual scram upon determination that the region has been entered, may be automated by extending the APRM flow-biased scram setpoint to encompass the region. Because the Manual BSP Scram Region boundary intersection with the plant-specific NCL is not higher than the intersection of the original 100% load line with the plant NCL, flow reduction events from the MELLLA+ region to the NCL would result in an entry into the Automated BSP Scram Region, and therefore an automatic reactor scram.

Automating the Manual BSP Scram Region provides an adequate instability prevention protection for operation in the entire MELLLA+ domain for interim situation when the CDA protection is temporarily unavailable. However, such a protection requires plant-specific system modifications that may include hardware and/or software changes. This feature may be implemented based on plant-specific considerations of the added benefits of continued operation in the MELLLA+ domain versus the added cost associated with the necessary system modifications.

Figures 7-9 and 7-10 illustrate the [[

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7.4.1 Automated BSP Scram Region Plant-Specific Application

Region Definition

The APRM flow-biased scram setpoint is extended to encompass the Manual BSP Region I boundary, defined in Section 7.2. [[

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The Automated BSP Scram Region is [[

]] any flow reduction event initiating from off-rated conditions and terminating inside the Automated BSP Scram Region, including all events terminating above the OLTP 100% load line, results in immediate automatic reactor scram.

Figure 7-11 illustrates the construction of the modified APRM flow-biased scram setpoints, including the Automated BSP Scram Region, [[

]] The figure also illustrates the APRM flow-biased rod block setpoints, which are constructed to provide the standard scram avoidance protection. [[

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Because a plant cycle specific assessment is required to confirm the applicability or update the Manual BSP Region I boundary, the Automated BSP Scram Region is also required to be confirmed or updated.

Actions

There are no required operator actions associated with the Automated BSP Scram Region because an automatic reactor scram is initiated upon entry.

7.5 BSP Options Application Summary

Two BSP options are described in this section, which may be used in the unlikely event the OPRM system is inoperable. They both provide effective SLMCPR protection.

7.5.1 BSP Option 1

This option comprises manually implemented region boundaries (Scram and Controlled Entry Regions) and specified manual operator actions, as described in Section 7.2, Manual BSP Region Boundaries Generation, and restrictions in the allowable operating domain as described in

Section 7.3, BSP Boundary Generation. Figure 7-12 illustrates this option for the BWR/4 example of Figure 7-6.

In Figure 7-12, the Manual BSP Region I is the same as the base Manual BSP Region I because the base region is confirmed, as illustrated in Figure 7-6. The Manual BSP Region II in Figure 7-12 is larger relative to the base Manual BSP Region II shown in Figure 7-6 as a result of the conservative stability criteria applied at its high end, thus illustrating the added measure to ensure higher stability margin for off-rated operation below the BSP Boundary.

7.5.2 BSP Option 2

This option comprises the Automated BSP Scram Region implemented by the APRM flow-biased scram setpoint, as described in Section 7.4, Automated BSP Scram Region Generation, and the Manual BSP Controlled Entry Region and associated manual operator actions, as described in Section 7.2.3.2, Region II – Controlled Entry Region. The Manual BSP Region II boundary and actions are the same for both BSP Options 1 and 2 and the Manual BSP Region I is not required for BSP Option 2. Figure 7-13 illustrates this option for the BWR/4 example of Figure 7-6. For this option, the APRM flow-biased setpoints may intersect the Manual BSP Region II. In this case, the required operator actions for the Manual BSP Region II are further restricted by the APRM flow-biased setpoints.

When the DSS-CD solution is inoperable, the Automated BSP option requires that the licensee implement the Automated BSP scram option within 12 hours. During this time, Manual BSP is used typically as specified by Action "I" in Table 8-1 and Appendix A. This is consistent with the Standard TS requirement, as it takes some time to switch from DSS-CD to the automated BSP protection. The plant then has 90 days to provide a report to the NRC staff with a corrective action plan and schedule for NRC staff review.

If the Automated BSP option cannot be implemented, the TS requires the licensee to implement the manual BSP option within the next 12 hours as specified by Action "J" in Table 8-1 and Appendix A. This requires the licensee to reduce operation of the plant to below the BSP Boundary defined in the Core Operating Limits Report (COLR). The licensee then has 120 days to restore the DSS-CD solution or shutdown the plant. If neither the Automated or manual BSP options can be implemented, the plant must be placed in a condition in which the Limiting

Condition for Operation (LCO) does not apply (i.e., less than 20 percent RTP or Mode 2) in less than 4 or 6 hours, depending on the LCO applicability as specified by Action "K" in Table 8-1 and Appendix A.

7.5.3 BSP Reload Application

A plant cycle specific assessment is required to confirm the applicability or update the BSP option for reload-specific fuel, core design, and operating strategy. [[

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A conservative representation of the Manual BSP Regions, BSP Boundary or Automated BSP Scram Region may be established to minimize the need for cycle-specific updates.

Implementation of a BSP option will require plant-specific Technical Specifications (TS) changes and associated justifications. Section 8.0 discusses the recommended TS and Bases changes.

7.5.4 ABSP Setpoint Implementation

The Manual BSP Regions, BSP Boundary, and APRM flow-biased setpoints associated with the Automated BSP Scram Region are defined in the COLR.

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Table 7-1 Manual BSP Regions Calculation Procedure

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Table 7-2 BSP Boundary Calculation Procedure

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Table 7-3 Summary of BSP Boundary Calculation Examples

Example No.	Figure No.	Description
1	7-5	BWR/6, Nominal feedwater temperature
2	7-6	BWR/4, Nominal rated feedwater temperature
3	7-7	BWR/4, Reduced rated feedwater temperature (- 23°F)
4	7-8	BWR/4, Reduced rated feedwater temperature (- 55°F)

Note: Examples 2 through 4 comprise of different BWR/4 plants.

Figure 7-1 Base Manual BSP Regions Generation Basis Relative to ICA Regions (100% EPU = 120% OLTP)

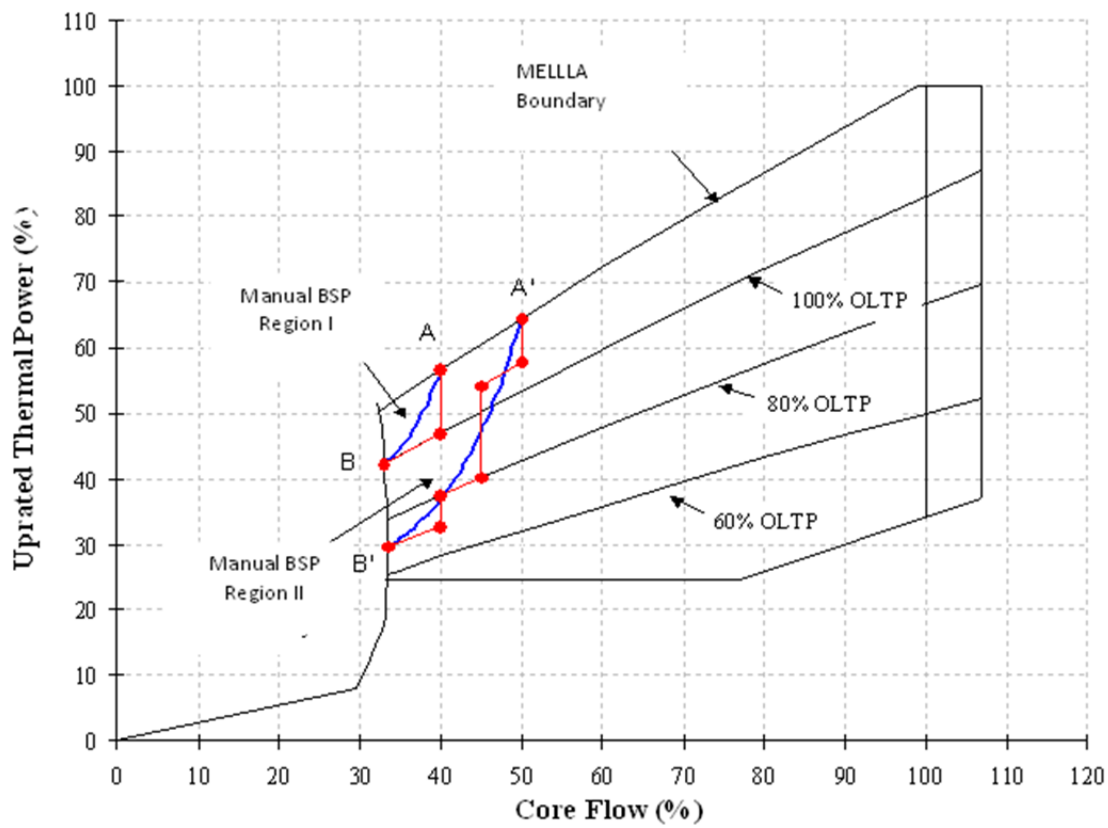

Figure 7-2 MELLLA+ Base Manual BSP Regions

(100% EPU = 120% OLTP)

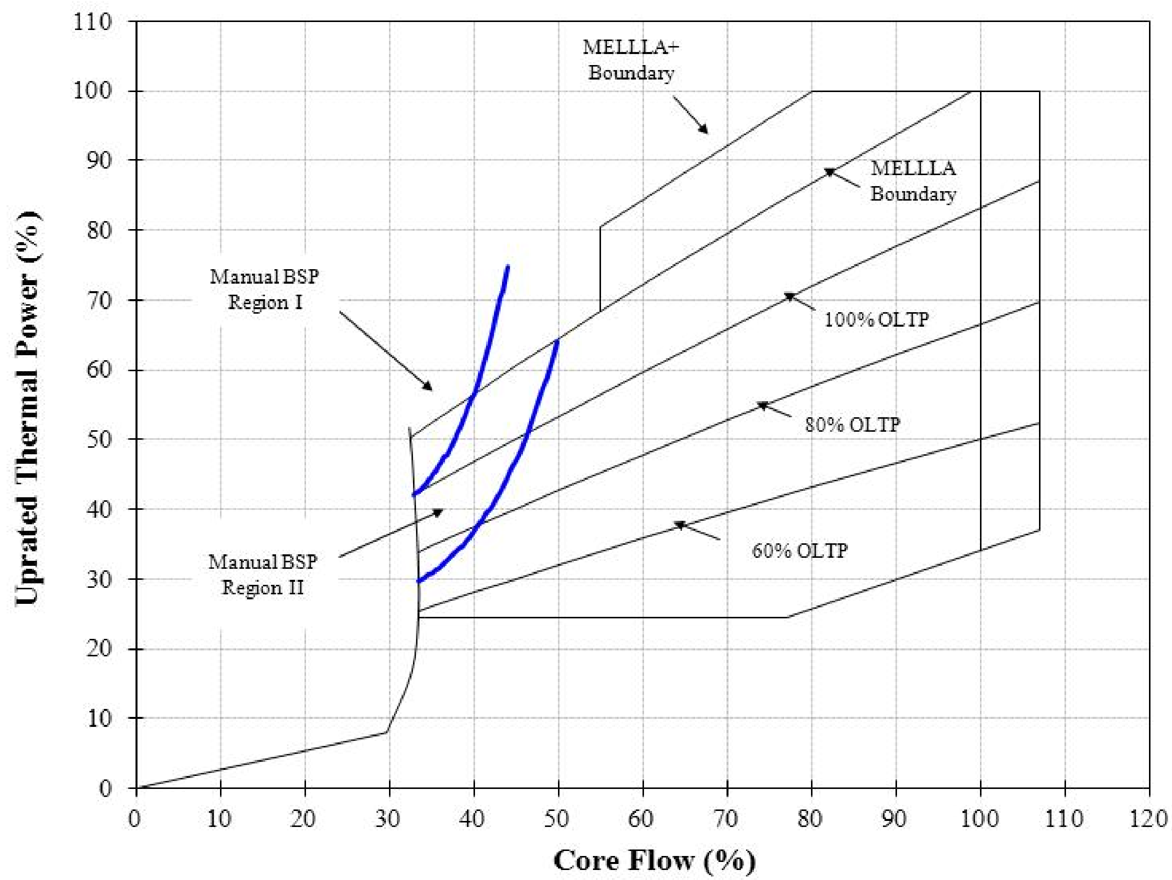

Figure 7-3 Stability Criteria

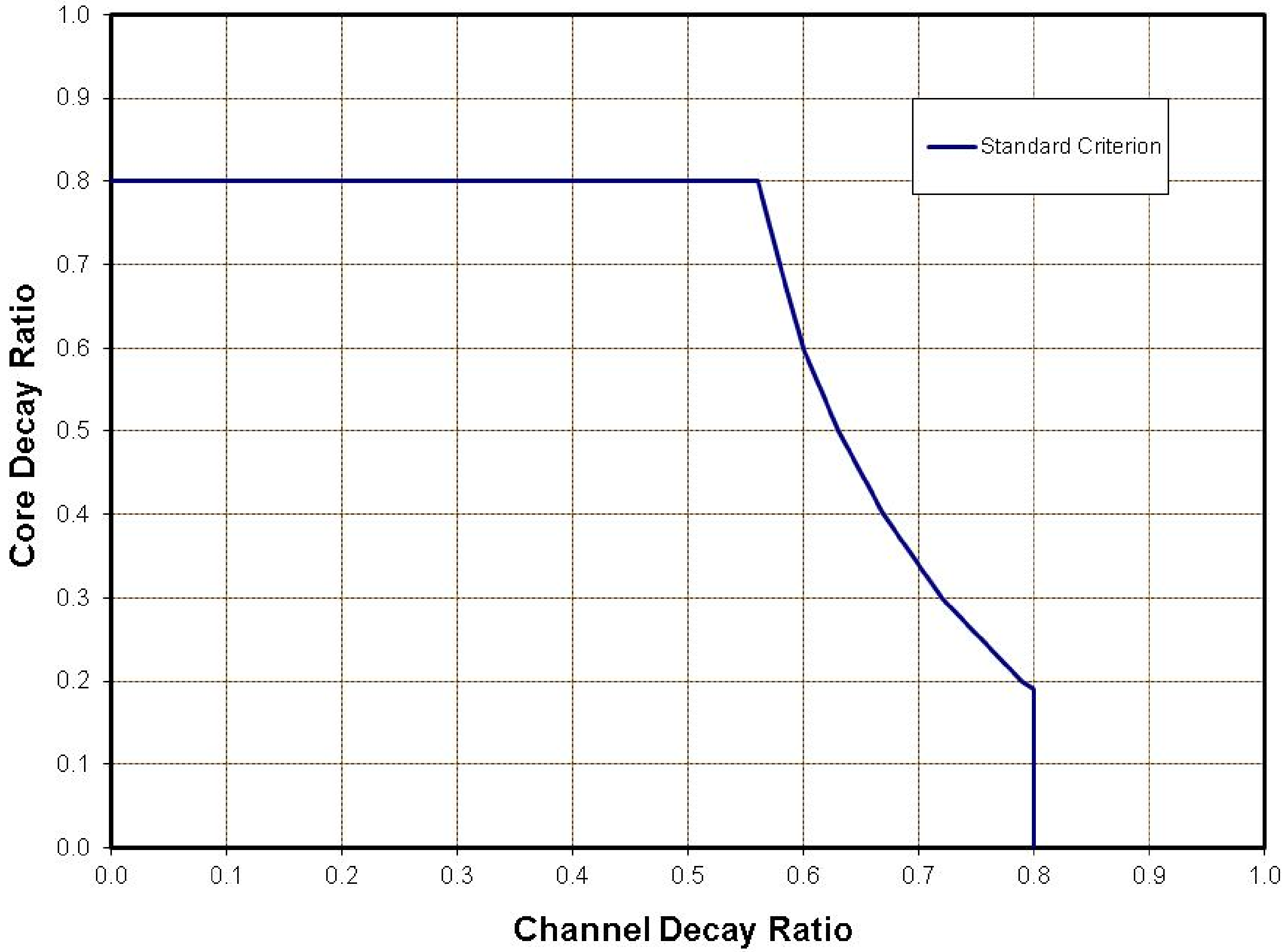

Figure 7-4 Example BWR/6 Manual BSP Regions Confirmation
(100% EPU = 120% OLTP)

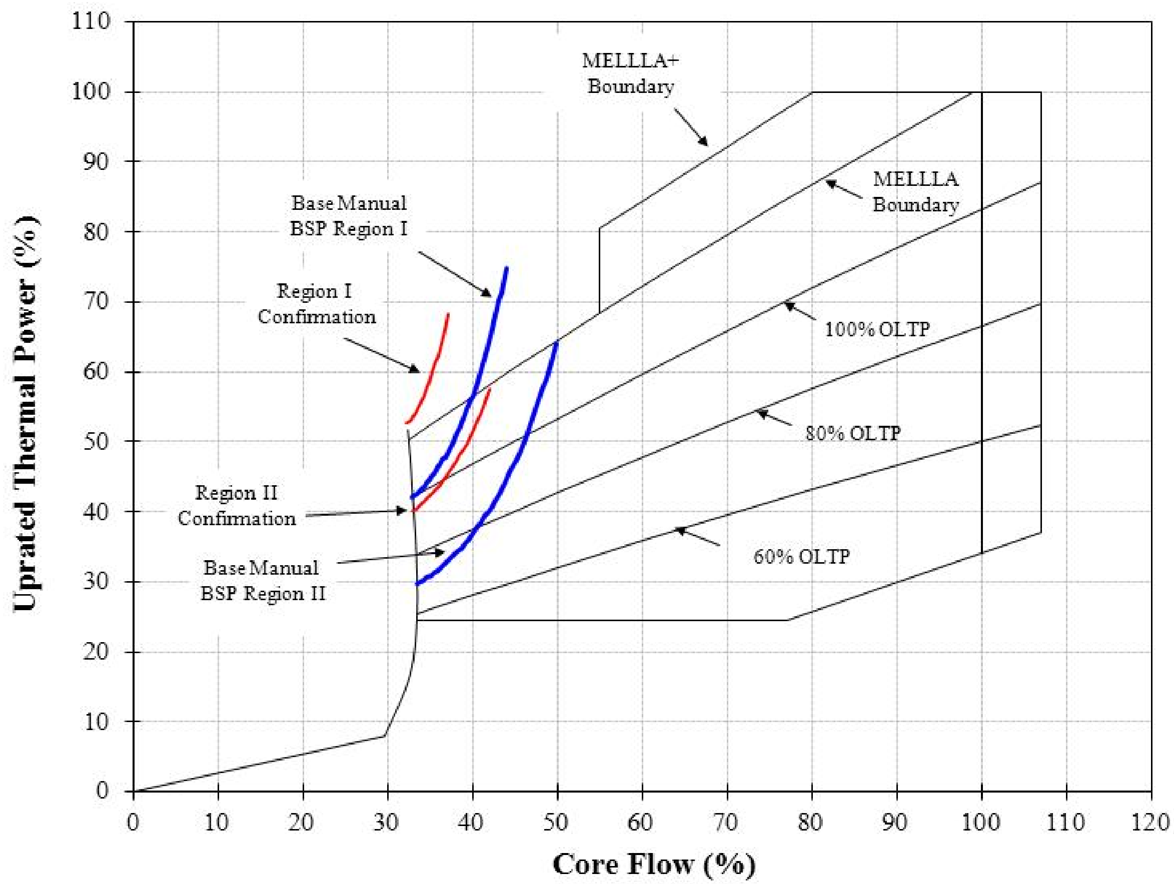

Figure 7-5 Example 1: BWR/6 Manual BSP Region I Confirmation and BSP Boundary (100% EPU = 120% OLTP, Nominal Feedwater Temperature)

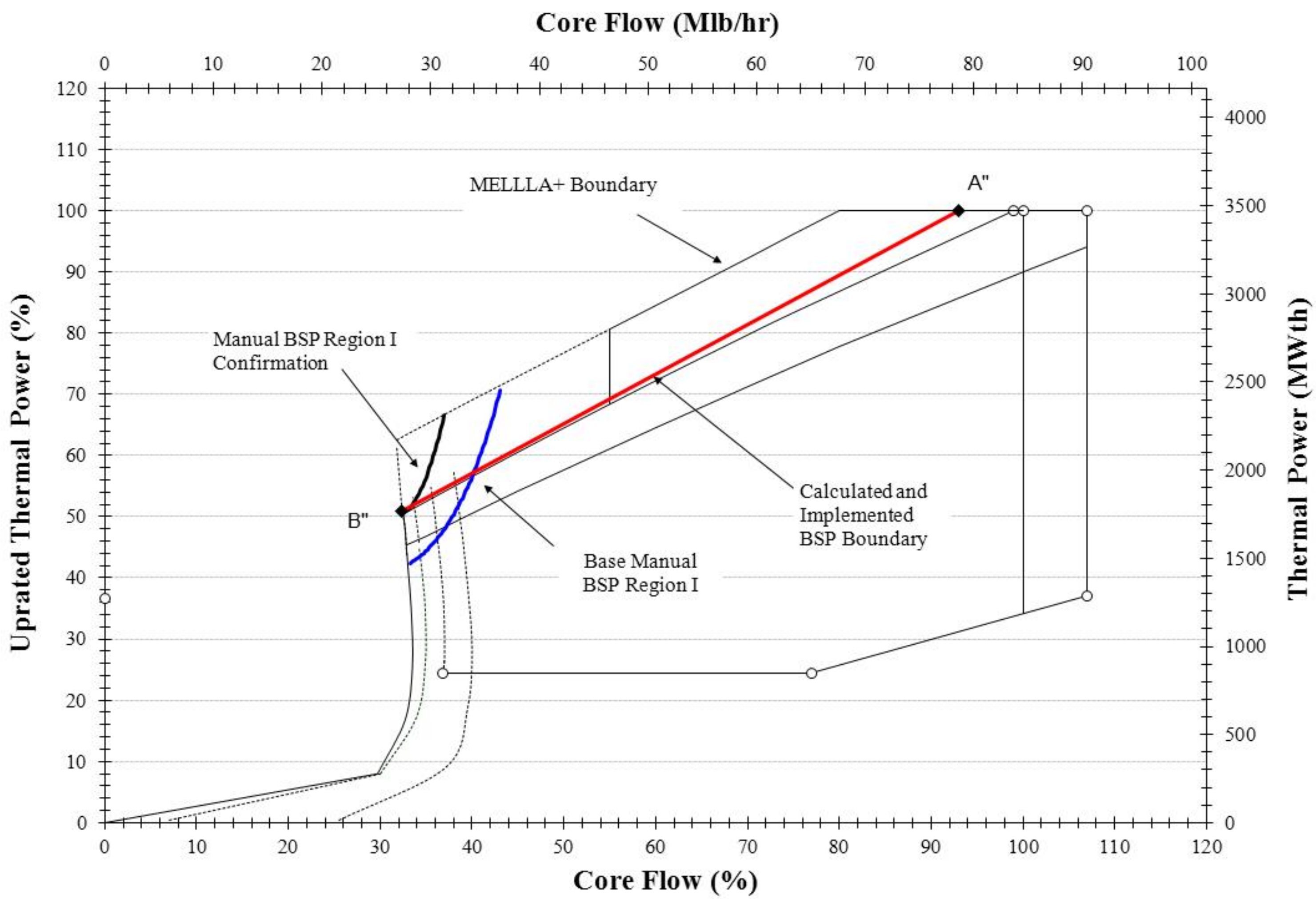

Figure 7-6 Example 2: BWR/4 Manual BSP Region I Confirmation and BSP Boundary (100% EPU = 120% OLTP, Nominal Feedwater Temperature)

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Figure 7-7 Example 3: BWR/4 Manual BSP Region I Confirmation and BSP Boundary (100% EPU = 120% OLTP, 23°F Feedwater Temperature Reduction)

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Figure 7-8 Example 4: BWR/4 Manual BSP Region I Confirmation and BSP Boundary (100% EPU = 120% OLTP, 55°F Feedwater Temperature Reduction)

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Figure 7-9 Scram Timing Illustration for BSP Option 2 [[ ]]

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Figure 7-10 Scram Timing Illustration for BSP Option 2 [[ ]]

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Figure 7-11 Automated BSP Region I Modified APRM Flow Biased Setpoint Construction

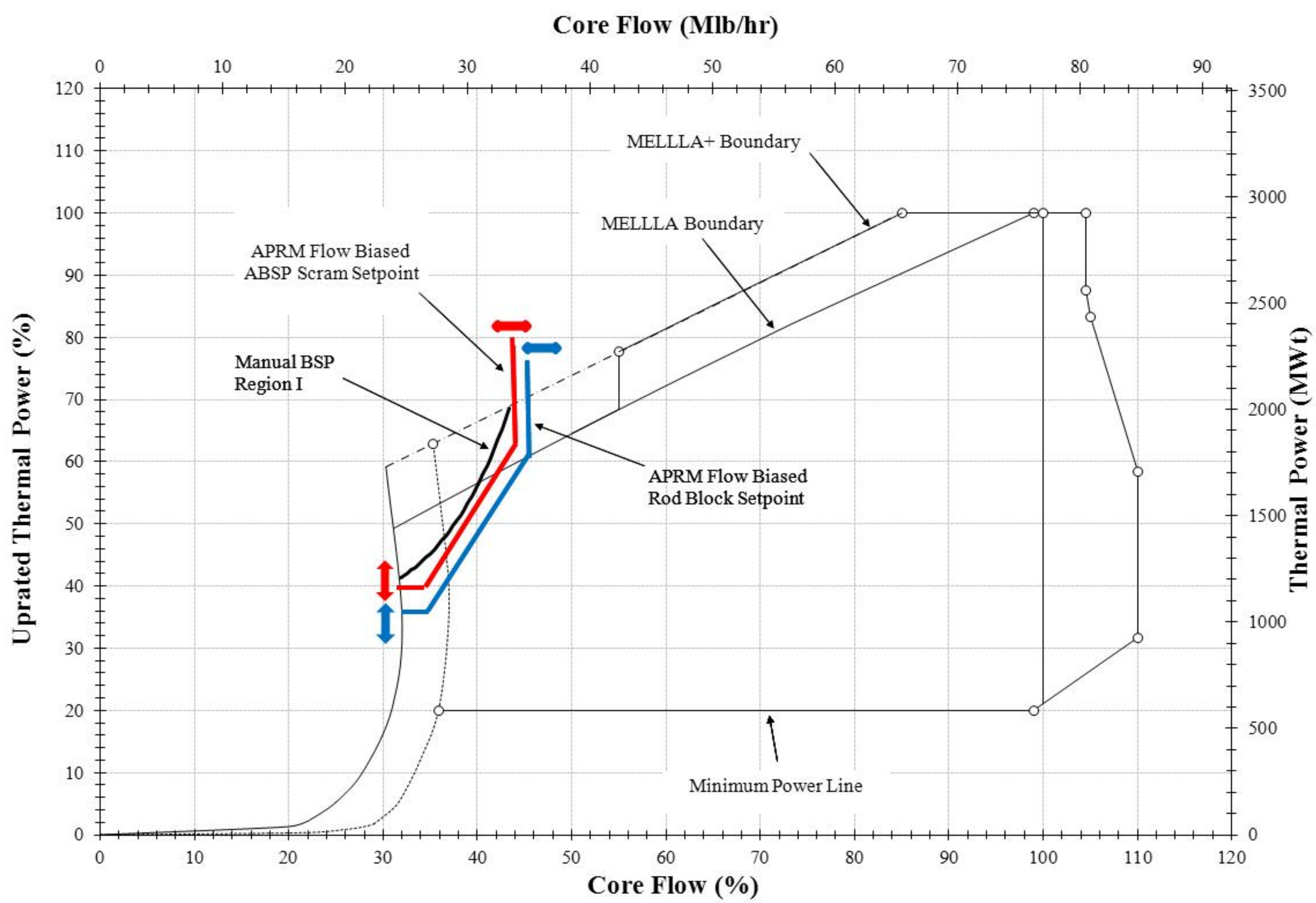

Figure 7-12 BSP Option 1 Illustration

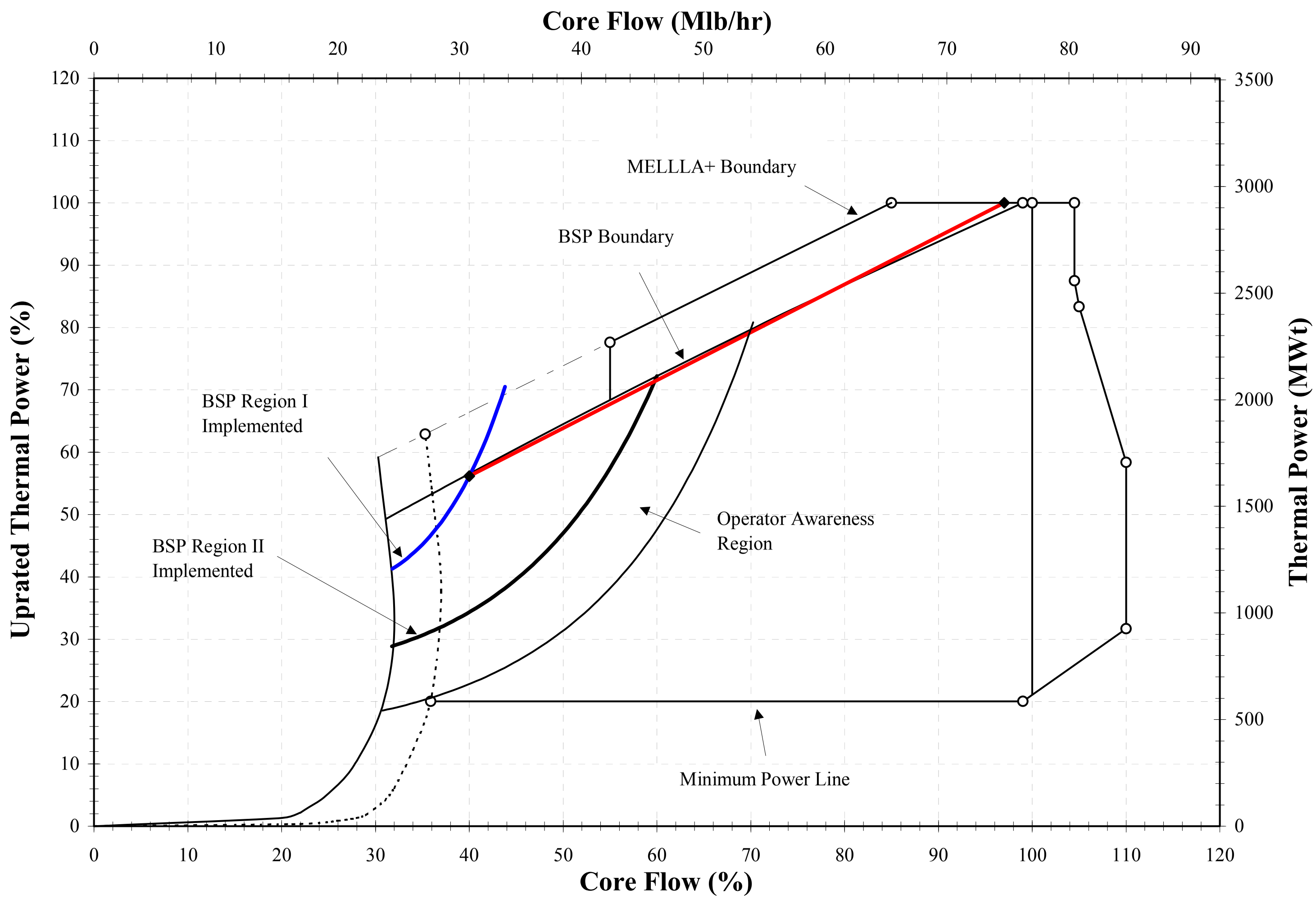

Figure 7-13 BSP Option 2 Implementation

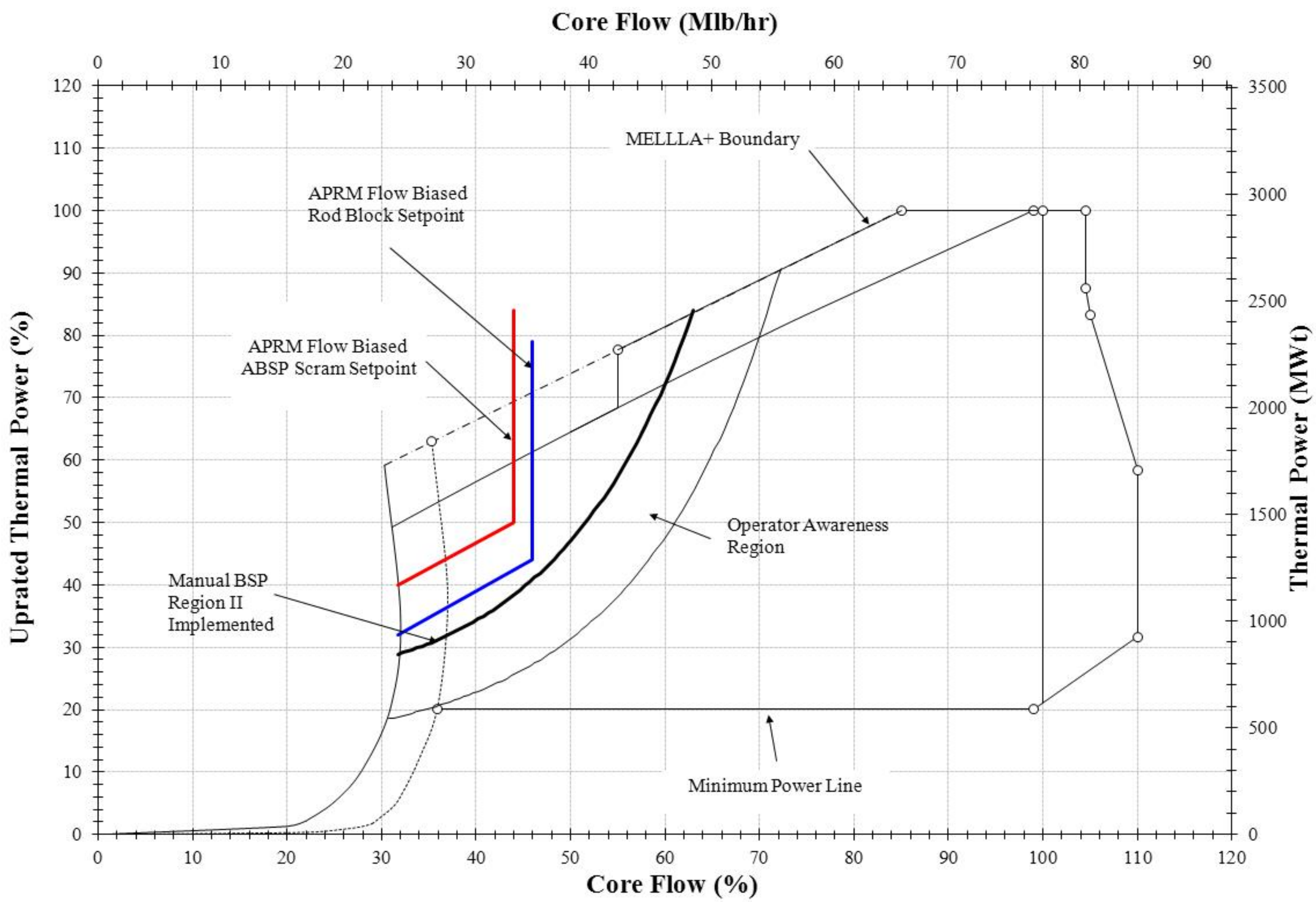

Figure 7-14 [[ ]]

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Figure 7-15 [[ ]]

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Figure 7-16 Scram Timing Illustration for ABSP vs. CDA

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8.0 EFFECT ON TECHNICAL SPECIFICATIONS

Changes to the Technical Specifications (TS) and Bases are required to address the implementation of DSS-CD. This section provides examples of changes to TS and Bases as generic guidance in developing the plant-specific license amendment to address DSS-CD implementation. Differences in plant-specific changes to the TS and Bases from those examples provided herein may be justifiable based on the plant-specific licensing basis and the inclusion of other licensing basis changes in the plant's license amendment request.

The example TS and Bases changes for a BWR/4 implementing Standard Technical Specifications, Revision 3.1, 12/01/05 (Reference 26) are provided in Appendices A and B. The changes also assume prior implementation of the TS and Bases proposed in Reference 13 for LTS Option III. Both Appendices A and B show the same changes to the TS and Bases. The changes in Appendix A are indicated with revision bars in the left margin with deletions shown by a strikeout fonts and additions shown by an underlined font. Appendix B provides an easier to read set of proposed TS and Bases with the incorporated changes indicated by revision bars only. In general, only pages with changes are shown, but in a few cases other pages are included to better show the context.

A summary of the changes in the TS and Bases is as follows:

1. The proposed changes reflect the implementation of the BSP in the event that the DSS-CD is inoperable,
2. Changes in the applicability requirements for DSS-CD,
3. Initial operation of the DSS-CD,
4. Elimination of an unnecessary Surveillance Requirement,
5. Additional core operating limits to the COLR, and
6. Update the applicable references.

Table 8-1 provides a description of the changes in the TS. This description assumes that the changes proposed for the BWR/4 Standard Technical Specifications in Reference 13 are the existing Technical Specifications. The proposed requirements reflect generic guidance to implement DSS-CD. The purpose of each change is presented to provide an understanding of the generic guidance. The individual plant-specific license amendment request will justify and evaluate the adequacy of necessary TS changes based on the plant's unique licensing basis and any other license basis changes.

Table 8-1 Description and Purpose of TS Changes for DSS-CD Implementation

Specification	Existing Requirement	Proposed Requirement	Purpose
TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation			
Required Action I.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	Initiate action to implement the Manual BSP Regions defined in the COLR.	The Manual BSP Region and required actions are described in Section 7.2. The change reflects a portion of the requirements for Backup Stability Protection if OPRM Upscale trip capability is not maintained.
Completion Time I.1	12 hours	Immediately	The purpose of the reduced Completion Time is to reflect the importance of limiting the period of time during which no automatic or alternate capability is in place.
Required Action I.2.1	None	Implement the Automated BSP Scram Region using the modified APRM flow-biased scram setpoints defined in the COLR.	Actions I.2.1 and I.2.2 are required actions both of which are required to be taken in conjunction with Action I.1 when OPRM Upscale trip capability is not maintained. The Automated BSP Scram Region and required actions are described in Section 7.4.
Completion Time I.2.1	None	12 hours	The Completion Time of 12 hours provides the plant operating staff sufficient time for implementation in an orderly manner.
Required Action I.2.2	None	Initiate action in accordance with Specification 5.6.6	Backup Stability Protection is a temporary means for protection against thermal-hydraulic instability events. While an extended period of inoperability does not warrant the shutdown of the plant with an automatic trip capability provided by the Automated BSP Scram Region, a written plan and schedule, with NRC oversight, to restore the required channels to operability provides appropriate management attention.

Specification	Existing Requirement	Proposed Requirement	Purpose
Completion Time I.2.2	None	90 days	The Completion Time of 90 days is adequate to allow time to evaluate the cause of the inoperability and to determine the appropriate corrective actions and schedule to restore the required channels to OPERABLE status.
Required Action J.1	None	Initiate action to implement the Manual BSP Regions defined in the COLR.	See Required Action I.1.
Completion Time J.1	None	Immediately	See Required Action I.1.
Required Action J.2	None	Reduce operation to below the BSP Boundary defined in the COLR.	Both Actions J.2 and J.3 are required in conjunction with Action J.1. If an automatic trip function for instability events is not maintained, operational conditions during which manual operator actions are sufficient must be established. The BSP Boundary and required actions are described in Section 7.3.
Completion Time J.2	None	12 hours	The Completion Time of 12 hours provides the plant operating staff sufficient time for implementation in an orderly manner.
Required Action J.3	I.2 Restore required channels to OPERABLE.	J.3 NOTE: LCO 3.0.4 is not applicable. Restore required channels to OPERABLE.	The addition of the note allows the initial startup to occur based on the manual BSP. This allows background operation of the automated systems for the purpose of data gathering and testing to determine proof of readiness.
Completion Time J.3	120 days	120 days (Same other than renumbering of the Completion Time)	Purpose unchanged.

Specification	Existing Requirement	Proposed Requirement	Purpose
Required Action K.1	Reduce THERMAL POWER to < [25]% RTP.	Reduce THERMAL POWER to less than [20]% RTP or Be in Mode 2.	The intent is to place the plant in a condition to which the LCO does not apply. A choice of different applicability requirements is provided, one of which would be proposed in the plant specific application. Either of the two choices represents regions of power-flow operation with minimal susceptibility to thermal-hydraulic oscillations. The [20]% RTP is a plant-specific value that is 5% below the lower boundary of the DSS-CD Armed Region.
Completion Time K.1	[4] hours	[4 or 6] hours	The Completion Time of [4 or 6] hours provides the plant operating staff sufficient time for implementation in an orderly manner. A choice of different Completion Times is provided, one of which would be addressed in the plant-specific application. The longer of the two choices of Completions Times addresses the action to a reduce operations to Mode 2.
SR 3.3.1.1.16	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ [30]% and recirculation drive flow is <[60]% of rated recirculation drive flow.	Delete	The DSS-CD automatically arms and the SR is unnecessary.
Table 3.3.1.1-1, Function 2.b, Allowable Value, footnote (c)	None	With OPRM Upscale (Function 2.f) inoperable, reset the APRM flow-biased setpoints to the values defined by the COLR to implement the Automated BSP Scram Region in accordance with Action I of this Specification.	The footnote is intended to reflect a possible change in the APRM allowable value due to implementation of the Automated BSP Scram Region described in Section 7.4.

Specification	Existing Requirement	Proposed Requirement	Purpose
Table 3.3.1.1-1, Function 2.f, Applicable Modes or Other Specified Conditions	≥ [25]% RTP	≥ [20]% RTP or Mode 1	A choice of different applicability requirements is provided, one of which would be addressed in the plant-specific application. Either one of which represents regions of power-flow operation where anticipated events could lead to thermal-hydraulic oscillations and related neutron flux oscillations. The [20]% RTP is a plant-specific value that is 5% below the lower boundary of the DSS-CD Armed Region.
Table 3.3.1.1-1, Function 2.f, Surveillance Requirements	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.16	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	See SR 3.3.1.1.16.
Table 3.3.1.1-1, Function 2.f, Footnote e	See COLR for OPRM period-based detection algorithm (PBDA) setpoint limits.	Following DSS-CD implementation, DSS-CD is not required to be armed while in the DSS-CD Armed Region during the first reactor startup and during the first controlled shutdown that passes completely through the DSS-CD Armed Region. However, DSS-CD is considered OPERABLE and shall be maintained OPERABLE and capable of automatically arming for operation at recirculation drive flow rates above the DSS-CD Armed Region.	The existing requirement is no longer applicable since the PBDA is no longer credited in the safety analysis. The proposed requirement addresses the limited operability requirements during the initial testing phase following DSS-CD implementation.

Specification	Existing Requirement	Proposed Requirement	Purpose
Changes in sections other than Specification 3.3.1.1			
5.6. 3, Core Operating Limits Report	The period-based algorithm (PBDA) setpoint for Function 2.f, Oscillation Power Range Monitor (OPRM) Upscale, for Specification 3.3.1.1	[For DSS-CD, the following is required in addition to the normal list of limits:] The Manual Backup Stability Protection (BSP) Scram Region (Region I), the Manual BSP Controlled Entry Region (Region II), [the modified APRM flow-biased setpoints used in the OPRM (Function 2.f), Automated BSP Scram Region, and the BSP Boundary] for Specification 3.3.1.1.	The existing PBDA is no longer credited in the safety analysis. Specification 3.3.1.1 includes additional core operating limits that must be addressed in the COLR. The choice of the Automated BSP Scram Region or the BSP Boundary, reflects the plant-specific option to implement BSP consistent with Section 7.5.
5.6. 6, OPRM Report	None	When a report is required by Condition I of LCO 3.3.1.1, "RPS Instrumentation," a report shall be submitted within 90 days of entering CONDITION I. The report shall outline the preplanned means to provide backup stability protection, the cause of the inoperability, and the plans and schedule for restoring the required instrumentation channels to OPERABLE status.	See Required Action I.2.2.

9.0 REFERENCES

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6. NEDE-33213P-A, “ODYSY Application for Stability Licensing Calculations Including Option I-D and II Long Term Solutions,” April 2009.
7. NEDE-32906P-A, Revision 3, “TRACG Application for Anticipated Operational Occurrences (AOO) Transient Analyses,” September 2006.
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19. NEDE-33147P, Revision 3, "DSS-CD TRACG Application," January 2011.

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21. NEDE-32906P, Supplement 3-A, Revision1, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10 for TRACG AOO and ATWS Overpressure Transients," April 2010.

22. Letter from S. A. Richards (NRC) to G. A. Watford (GE), "Amendment 26 to GE Licensing Topical Report NEDE-24011-P-A, "GESTAR II" Implementing Improved GE Steady-State Methods (TAC No. MA6481)"," FLN-1999-011, November 10, 1999.

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24. TVA to NRC, "Browns Ferry Nuclear Plant (BFN) - Unit 1, Technical Specifications (TS) Change TS-443 - Request for Additional Information (RAI) Regarding Oscillation Power Range Monitor (OPRM) - (TAC No. MC9565), TVA-BFN-TS-443, October 2, 2006.

25. NMC to NRC, "Response to Requests for Additional Information for License Amendment Request for Power Range Neutron Monitoring System Upgrade (TAC No. MD8064)," September 16, 2008.

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27. Letter from James F. Harrison (GEH) to NRC, "Response to Request for Additional Information Re: GE-Hitachi Nuclear Energy Americas Topical Report (TR) NEDC 33075P, Revision 7 and NEDO-33075, Revision 7, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution - Confirmation Density" (TAC No. ME6577)," MFN 12-078, June 27, 2012.

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APPENDIX A: EXAMPLE OF CHANGES TO BWR/4 STANDARD TECHNICAL SPECIFICATIONS - REDLINE/STRIKEOUT VERSION

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. <u>OR</u> A.2 Place associated trip system in trip.	12 hours 12 hours
B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. <u>OR</u> B.2 Place one trip system in trip.	6 hours 6 hours
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < [30]% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1 Initiate action to implement the Manual BSP Regions defined in the COLR~~alternate method to detect and suppress thermal hydraulic instability oscillations~~. AND I.2.1 Implement the Automated BSP Scram Region using the modified APRM flow-biased scram setpoints defined in the COLR. AND I.2.2 Initiate action in accordance with Specification 5.6.6.	~~12 hours~~Immediately 12 hours 90 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. Required Action and associated Completion Time of Condition I not met.	J.1 Initiate action to implement the Manual BSP Regions defined in the COLR.	Immediately
	AND	
	J.2 Reduce operation to below the BSP Boundary defined in the COLR.	12 hours
	AND	
	J.3 ---------NOTE---------- LCO 3.0.4 is not applicable ---------------------- Restore required channel to OPERABLE	120 days
~~J~~K. Required Action and associated Completion Time of Condition ~~I~~ J not met.	~~J~~K.1 [Reduce THERMAL POWER to ~~<~~less than [~~25~~20]% RTP or Be in Mode 2].	[4 or 6] hours

SURVEILLANCE REQUIREMENTS

-----------------------------------NOTES-----------------------------------

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.2	------------------NOTE------------------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. --- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP [plus any gain adjustment required by LCO 3.2.4, "Average Power Range Monitor (APRM) Setpoints"] while operating at ≥ 25% RTP.	7 days
SR 3.3.1.1.3	Adjust the channel to conform to a calibrated flow signal.	7 days
SR 3.3.1.1.4	------------------NOTE------------------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.6	Calibrate the local power range monitors.	[1000] MWD/T average core exposure
SR 3.3.1.1.7	Perform CHANNEL FUNCTIONAL TEST.	[92] days
SR 3.3.1.1.8	[Calibrate the trip units.	[92] days]

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.6 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.9	-------------------NOTES------------------- 1. Neutron detectors are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.10	Perform CHANNEL FUNCTIONAL TEST.	[18] months
SR 3.3.1.1.11	-------------------NOTES------------------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL CALIBRATION.	[18] months
SR 3.3.1.1.12	Verify the APRM Flow Biased Simulated Thermal Power - high time constant is ≤ [7] seconds.	[18] months
SR 3.3.1.1.13	Perform LOGIC SYSTEM FUNCTIONAL TEST.	[18] months
SR 3.3.1.1.14	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ [30]% RTP.	[18] months

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.15	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --- Verify the RPS RESPONSE TIME is within limits.	[18] months on a STAGGERED TEST BASIS
~~SR 3.3.1.1.16~~	~~Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥[30]% and recirculation drive flow is <[60]% of rated recirculation drive flow.~~	~~[18] months~~

Table 3.3.1.1-1 (page 1 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	[3]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [120/125] divisions of full scale
	5[(a)]	[3]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [120/125] divisions of full scale
b. Inop	2	[3]	G	SR 3.3.1.1.4 SR 3.3.1.1.13	NA
	5[(a)]	[3]	H	SR 3.3.1.1.5 SR 3.3.1.1.13	NA
2. Average Power Range Monitors					
a. Neutron Flux — High, (Setdown)	2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.9 SR 3.3.1.1.13	≤ [20]% RTP
b. Flow Biased Simulated Thermal Power — High	1	[2]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [0.58 W + 62]% RTP and ≤ [115.5]% RTP[(b)] [(c)]

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) [0.58 W + 62% - 0.58 ΔW]RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) With OPRM Upscale (Function 2.f) inoperable, reset the APRM flow-biased setpoints to the values defined by the COLR to implement the Automated BSP Scram Region in accordance with Action I of this Specification.

Table 3.3.1.1-1 (page 2 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors					
c. Fixed Neutron Flux – High	1	[2]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [120]% RTP
[d. Downscale	1	[2]	F	SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13	≥ [3]% RTP
e. Inop	1,2	[2]	G	SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13	NA
f. OPRM Upscale	[≥ [~~25~~20]% RTP or 1](e)	3(c)	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13 ~~SR 3.3.1.1.16~~	NA~~(e)~~
3. Reactor Vessel Steam Dome Pressure – High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [1054] psig
4. Reactor Vessel Water Level – Low, Level 3	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.15	≥ [10] inches
5. Main Steam Isolation Valve – Closure	1	[8]	F	SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [10]% closed
6. Drywell Pressure – High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [1.92] psig

(e) Following DSS-CD implementation, DSS-CD is not required to be armed while in the DSS-CD Armed Region during the first reactor startup and during the first controlled shutdown that passes completely through the DSS-CD Armed Region. However, DSS-CD is considered OPERABLE and shall be maintained OPERABLE and capable of automatically arming for operation at recirculation drive flow rates above the DSS-CD Armed Region.

~~(e) See COLR for OPRM period-based detection algorithm (PBDA) setpoint limits.~~

Table 3.3.1.1-1 (page 3 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level — High					
a. Resistance Temperature Detector	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
b. Float Switch	1,2	[2]	G	SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
8. Turbine Stop Valve - Closure	≥ [30]% RTP	[4]	E	SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≤ [10]% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ [30]% RTP	[2]	E	SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ [600] psig
10. Reactor Mode Switch - Shutdown Position	1,2	[2]	G	SR 3.3.1.1.10 SR 3.3.1.1.13	NA
	5(a)	[2]	H	SR 3.3.1.1.10 SR 3.3.1.1.13	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

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Table 3.3.1.1-1 (page 4 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
11. Manual Scram	1,2	[2]	G	SR 3.3.1.1.5 SR 3.3.1.1.13	NA
	5[(a)]	[2]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

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5.6.3 CORE OPERATING LIMITS REPORT

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

[The individual specifications that address core operating limits must be referenced here.]

[For DSS-CD, the following is required in addition to the normal list of limits:]

~~1. The period based algorithm (PBDA) setpoint for Function 2.f, Oscillation Power Range Monitor (OPRM) Upscale, for Specification 3.3.1.1.~~

1. The Manual Backup Stability Protection (BSP) Scram Region (Region I), the Manual BSP Controlled Entry Region (Region II), [the modified APRM flow-biased setpoints used in the OPRM (Function 2.f), Automated BSP Scram Region, and the BSP Boundary] for Specification 3.3.1.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

[Identify the Topical Report(s) by number and title or identify the staff Safety Evaluation Report for a plant specific methodology by NRC letter and date. The COLR will contain the complete identification for each of the Technical Specification referenced topical reports used to prepare the COLR (i.e., report number, title, revision, date, and any supplements).]

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.4 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

[The individual specifications that address RCS pressure and temperature limits must be referenced here.]

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

[Identify the Topical Report(s) by number and title or identify the NRC Safety Evaluation for a plant specific methodology by NRC letter and date. The PTLR will contain the complete identification for each of the TS referenced Topical Reports used to prepare the PTLR (i.e., report number, title, revision, date, and any supplements).]

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5.6 Reporting Requirements

5.6.6 OPRM Report

When a report is required by Condition I of LCO 3.3.1.1, "RPS Instrumentation," a report shall be submitted within 90 days of entering CONDITION I. The report shall outline the preplanned means to provide backup stability protection, the cause of the inoperability, and the plans and schedule for restoring the required instrumentation channels to OPERABLE status.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

BWR/6 STS Note: The wording of the BASES descriptions of APRM Functions is somewhat different from the corresponding Functions for the BWR/4 ISTS to reflect slight differences in the architecture. However, the replacement text will be very similar to that shown in this example mark-up.

Average Power Range Monitor

2.a. Average Power Range Monitor Neutron Flux - High, Setdown

The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux - High, Setdown Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux - High, Setdown Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux - High Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux - High, Setdown Function will provide the primary trip signal for a corewide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux - High, Setdown Function. However, this Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 25% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 25% RTP.

The APRM System is divided into two groups of channels with three APRM channel inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux - High, Setdown with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Average Power Range Monitor Neutron Flux - High, Setdown Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists. In MODE 1, the Average Power Range Monitor Neutron Flux - High Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events.

2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power - High

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Fixed Neutron Flux - High Function Allowable Value. The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR SL is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Fixed Neutron Flux - High Function will provide a scram signal before the Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function setpoint is exceeded.

The APRM System is divided into two groups of channels with four APRM inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Flow Biased Simulated Thermal Power - High with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located. Each APRM channel receives two total drive flow signals representative of total core flow. The total drive flow signals are generated by four flow units, two of which supply signals to the trip system A APRMs, while the other two supply signals to the trip system B APRMs. Each flow unit signal is provided by summing up the flow signals from the two recirculation loops. To obtain the most conservative reference signals, the total flow signals from the two flow units (associated with a trip system as described above) are routed to a low auction circuit associated with each APRM. Each APRM's auction circuit selects the lower of the two flow unit signals for use as the scram trip reference for that particular APRM. Each required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channel only requires an input from one OPERABLE flow unit, since the individual APRM channel will perform the intended function with only one OPERABLE flow unit input. However, in order to maintain single failure criteria for the Function, at least one required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channel in each trip system must be capable of maintaining an OPERABLE flow unit signal in the event of a failure of an auction circuit, or a flow unit, in the associated trip system (e.g., if a flow unit is inoperable, one of the two required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channels in the associated trip system must be considered inoperable).

The clamped Allowable Value is based on analyses that take credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function for the mitigation of the loss of feedwater heating event. The THERMAL POWER time constant of < 7 seconds is based on the fuel heat transfer dynamics and provides a signal proportional to the THERMAL POWER.

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.c. Average Power Range Monitor Fixed Neutron Flux - High

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Fixed Neutron Flux - High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 5, the Average Power Range Monitor Fixed Neutron Flux - High Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 6) takes credit for the Average Power Range Monitor Fixed Neutron Flux - High Function to terminate the CRDA.

The APRM System is divided into two groups of channels with three APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Fixed Neutron Flux - High with two channels in each trip system arranged in a one-out-of- two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Fixed Neutron Flux - High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Fixed Neutron Flux - High Function is assumed in the CRDA analysis, which is applicable in MODE 2, the Average Power Range Monitor Neutron Flux - High, Setdown Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Range Monitor Fixed Neutron Flux - High Function is not required in MODE 2.

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2.d. Average Power Range Monitor - Downscale

This signal ensures that there is adequate Neutron Monitoring System protection if the reactor mode switch is placed in the run position prior to the APRMs coming on scale. With the reactor mode switch in run, an APRM downscale signal coincident with an associated Intermediate Range Monitor Neutron Flux - High or Inop signal generates a trip signal. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The APRM System is divided into two groups of channels with three inputs into each trip system. The system is designed to allow one channel in each trip system to be bypassed. Four channels of Average Power Range Monitor - Downscale with two channels in each trip system arranged in a one-out-of- two logic are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. The Intermediate Range Monitor Neutron Flux - High and Inop Functions are also part of the OPERABILITY of the Average Power Range Monitor - Downscale Function (i.e., if either of these IRM Functions cannot send a signal to the Average Power Range Monitor - Downscale Function, the associated Average Power Range Monitor - Downscale channel is considered inoperable).

The Allowable Value is based upon ensuring that the APRMs are in the linear scale range when transfers are made between APRMs and IRMs.

This Function is required to be OPERABLE in MODE 1 since this is when the APRMs are the primary indicators of reactor power.

2.e. Average Power Range Monitor - Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than "Operate," an APRM module is unplugged, the electronic operating voltage is low, or the APRM has too few LPRM inputs (< 11), an inoperative trip signal will be received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each trip system may be inoperable without resulting in an RPS trip signal. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Four channels of Average Power Range Monitor - Inop with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

2.f. Oscillation Power Range Monitor (OPRM) Upscale

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

Reference [19] describes the Detect and Suppress - Confirmation Density (DSS-CD) long-term stability solution and the licensing basis Confirmation Density Algorithm (CDA). ~~and~~ Reference [19] also describes the DSS-CD Armed Region and the~~References [15], [16] and [17] describe~~ three additional algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (PBDA), the amplitude based algorithm (ABA), and the growth rate algorithm (GRA). All ~~three~~ four algorithms are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the ~~period based detection algorithm~~CDA. The remaining three algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY ~~for Technical Specification purposes~~is based only on the ~~period based detection algorithm~~ CDA.

The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms.

DSS-CD operability requires at least 8 responsive OPRM cells per channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is [at ≥~~[~~20~~5]~~% RTP, which is established as a power level that is greater than or equal to 5% below the lower boundary of the Armed Region~~, which is 20% RTP or in Mode 1],~~. This requirement is designed to encompass~~ing~~ the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. ~~Within this region, t~~The ~~automatic trip is enabled~~OPRM Upscale Function is automatically trip-enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is greater than or equal to ~~the ≥[30]~~25% RTP corresponding to the plant-specific MCPR monitoring threshold and reactor ~~core flow, as indicated by~~ recirculation drive flow, is ~~<~~ less than [~~60~~75 for MELLLA+ or 70 for MELLLA]% of rated flow~~, the operating region where actual thermal-hydraulic oscillations may occur~~. ~~The~~

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

~~lower bound, [25]% RTP, is chosen to provide margin in the unlikely event of loss of feedwater heating while the plant is operating below the [30]% automatic OPRM Upscale trip enable point. Loss of feedwater heating is the only identified event that could cause reactor power to increase into the region of concern *without operator action*.~~ . This region is the OPRM Armed Region. Note e allows for entry into the DSS-CD Armed Region without automatic arming of DSS-CD prior to completely passing though the DSS-CD Armed Region during both a single startup and a single shutdown following DSS-CD implementation. Note e reflects the need for plant data collection in order to test the DSS-CD equipment. Testing the DSS-CD equipment ensures its proper operation and prevents spurious reactor trips. Entry into the DSS-CD Armed Region without automatic arming of DSS-CD during this initial testing phase also allows for changes in plant operations to address maintenance or other operational needs. However, during this initial testing period, the OPRM upscale function is OPERABLE and DSS-CD operability and capability to automatically arm shall be maintained at recirculation drive flow rates above the DSS-CD Armed Region flow boundary.

An OPRM Upscale trip is issued from an ~~APRM~~ OPRM channel when the ~~period based detection~~confirmation density algorithm in that channel detects oscillatory changes in the neutron flux, indicated by period confirmations and amplitude exceeding specified setpoints for a specified number of OPRM cells in the channel. ~~the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip.~~ An OPRM Upscale trip is also issued from the channel if ~~either~~ any of the defense-in-depth algorithms (PBDA, ABA, GRA) ~~the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux~~exceed ~~the~~its trip condition for one or more cells in that channel.

Three of the four channels are required to be operable. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the MCPR SL is exceeded. There is no allowable value for this function.

The OPRM Upscale function settings are not traditional instrumentation setpoints determined under an instrument setpoint methodology. In accordance with the NRC Safety Evaluation for Amendment [159] (Ref. [21]), the OPRM Upscale Function is not LSSS SL-related and Reference 20 confirms that the OPRM Upscale Function settings based on DSS-CD also do not have traditional instrumentation setpoints determined under an instrument setpoint methodology.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Reactor Vessel Steam Dome Pressure - High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure - High Function initiates a scram for transients that results in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 5, reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux - High signal, not the Reactor Vessel Steam Dome Pressure - High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Vessel Steam Dome Pressure - High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure - High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the RCS is pressurized and the potential for pressure increase exists.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of Manual Scram with two channels in each trip system arranged in a one-out-of-two logic are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

------------------------REVIEWER'S NOTE---------------------
Certain LCO Completion Times are based on approved topical reports. In order for a licensee to use the times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.

A Note has been provided to modify the ACTIONS related to RPS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

<u>A.1 and A.2</u>

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 10) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip

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ACTIONS (continued)

system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 10 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 10, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

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ACTIONS (continued)

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram [or RPT]), Condition D must be entered and its Required Action taken.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 8 (Turbine Stop Valve--Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

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ACTIONS (continued)

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1, F.1, and G.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Action E.1 is consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

I.1

If OPRM Upscale trip capability is not maintained, Condition I exists and Backup Stability Protection (BSP) is required. ~~Reference [14] justified use of alternate methods to detect and suppress oscillations for a limited period of time.~~ The ~~m~~Manual BSP Regions are described in Reference [19]. The ~~alternatem~~Manual BSP Regions ~~methods are~~ are procedurally established consistent with the guidelines identified in Reference [~~18~~19] and requir~~ing~~e specified manual operator actions~~action to scram the plant~~ if certain predefined ~~events~~ operational conditions occur.

ACTIONS (continued)

The Completion Time of immediate is based on the importance of ~~The 12 hour allowed action time is based on engineering judgment to allow orderly transition to the alternate methods while~~ limiting the period of time during which no automatic or alternate detect and suppress trip capability is ~~formally~~ in place. ~~Based on the small probability of an instability event occurring at all, the 12 hours is judged to be reasonable.~~

I.2.1 and I.2.2

Actions I.2.1 and I.2.2 are both required to be taken in conjunction with Action I.1 if OPRM Upscale trip capability is not maintained. As described in Section 7.4 of Reference [19], the Automated BSP Scram Region is designed to avoid reactor instability by automatically preventing entry into the region of the power and flow-operating map that is susceptible to reactor instability. The reactor trip would be initiated by the modified APRM flow-biased scram setpoints for flow reduction events that would have terminated in the Manual BSP Region I. The Automated BSP Scram Region ensures an early scram and SLMCPR protection.

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, and based on the importance of restoring an automatic reactor trip for thermal hydraulic instability events.

Backup Stability Protection is intended as a temporary means to protect against thermal-hydraulic instability events. The reporting requirements of Specification 5.6.6 document the corrective actions and schedule to restore the required channels to an OPERABLE status. The Completion Time of 90 days is adequate to allow time to evaluate the cause of the inoperability and to determine the appropriate corrective actions and schedule to restore the required channels to OPERABLE status.

J.1

If the Required Actions I are not completed within the associated Completion Times, then Action J is required. The Bases for the Manual BSP Regions and associated Completion Time is addressed in the Bases for I.1. The Manual BSP Regions are required in conjunction with the BSP Boundary.

J.2

The BSP Boundary, as described in Section 7.3 of Reference [19], defines an operating domain where potential instability events can be effectively addressed by the specified BSP manual operator actions. The BSP Boundary is constructed such that the immediate final statepoint for a flow reduction event initiated from this boundary and terminated at the core

ACTIONS (continued)

natural circulation line (NCL) would not exceed the Manual BSP Region I stability criterion. Potential instabilities would develop slowly as a result of the feedwater temperature transient (Reference [19]).

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, to reach the specific condition from full power conditions in an orderly manner and without challenging plant system.

J.3

Backup Stability Protection (BSP) is a temporary means for protection against thermal-hydraulic instability events. An extended period of inoperability without automatic trip capability is not justified. Consequently, the required channels are required to be restored to OPERABLE status within 120 days.

~~The alternate method to detect and suppress oscillations implemented in accordance with I.1 was evaluated (Reference [14]) based on use up to 120 days only. The evaluation, b~~Based on engineering judgment, ~~concluded that~~ the likelihood of an instability event that could not be adequately handled by the ~~alternate methods~~use of the BSP Regions (See Action J.1) and the BSP Boundary (See J.2) during ~~this~~ a 120-~~-~~day period ~~was~~ is negligibly small. The 120-day period is intended ~~to be an outside limit~~ to allow for the case where limited design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. This action is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to normally be accomplished within the completion times allowed for Actions for Conditions A and B.

A Note is provided to indicate that LCO 3.0.4 is not applicable. The intent of that note is to allow plant startup while operating within the 120-day Completion Time for Required Action J.3. The primary purpose of this exclusion is to allow an orderly completion of design and verification activities, in the event of a required design change, without undue impact on plant operation.

ACTIONS (continued)

K.1

If the required channels are not restored to OPERABLE status and the Required Actions of J are not met within the associated Completion Times, then the plant must be placed in an operating condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least [20% RTP or Mode 2] within [4 or 6] hours. The allowed Completion Time is reasonable, based on operating experience, to reach the specified operating power level from full power conditions in an orderly manner and without challenging plant systems.

------------------------REVIEWER'S NOTE---------------------
Certain Frequencies are based on approved topical reports. In order for a licensee to use these Frequencies, the licensee must justify the Frequencies as required by the staff SER for the topical report.

SURVEILLANCE REQUIREMENTS (continued)

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column ofTable 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

<u>SR 3.3.1.1.1</u>

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The agreement criteria includes an expectation of one decade of overlap when transitioning between neutron flux instrumentation. The overlap between SRMs and IRMs must be demonstrated prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs. This will ensure that reactor power will not be increased into a neutron flux region without adequate ndication. The overlap between IRMs and APRMs is of concern when reducing power into the IRM range (entry into MODE 2 from MODE 1). On power

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SURVEILLANCE REQUIREMENTS (continued)

increases, the system design will prevent further increases (by initiating a rod block) if adequate overlap is not maintained. Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block or IRM upscale rod block. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on Range 1 before SRMs have reached the upscale rod block.

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channels(s) declared inoperable. Only those appropriate channels that are required in the current MODE or condition should be declared inoperable.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoints," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of calculated MFLPD. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.6.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). At 25% RTP, the

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SURVEILLANCE REQUIREMENTS (continued)

Surveillance is required to have been satisfactorily performed within the last 7 days, in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function uses the recirculation loop drive flows to vary the trip setpoint. This SR ensures that the total loop drive flow signals from the flow units used to vary the setpoint is appropriately compared to a calibrated flow signal and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. Each flow signal from the respective flow unit must be ≤ 105% of the calibrated flow signal. If the flow unit signal is not within the limit, one required APRM that receives an input from the inoperable flow unit must be declared inoperable.

The Frequency of 7 days is based on engineering judgment, operating experience, and the reliability of this instrumentation.

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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SURVEILLANCE REQUIREMENTS (continued)

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 9).

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. In accordance with Reference 10, the scram contacts must be tested as part of the Manual Scram Function. A Frequency of 7 days provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis of Reference 11. (The Manual Scram Function's CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions' Frequencies.)

SR 3.3.1.1.6

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The [1000] MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.6 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.7 and SR 3.3.1.1.10

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.7 is based on the reliability analysis of Reference 10.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.8

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 10.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.9 and SR 3.3.1.1.11

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the [1000] MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.6). A second Note is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

The Frequency of SR 3.3.1.1.9 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis (Ref. 22). The Frequency of SR 3.3.1.1.11 is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.12

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function uses an electronic filter circuit to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This filter circuit is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The Surveillance filter time constant must be verified to be ≤ 7 seconds to ensure that the channel is accurately reflecting the desired parameter.

The Frequency of 18 months is based on engineering judgment considering the reliability of the components.

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.9 and SR 3.3.1.1.11 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.13

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.14

This SR ensures that scrams initiated from the Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ 30% RTP to ensure that the calibration remains valid.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.15

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements.

[----------------------REVIEWER'S NOTE-------------------------
The following Bases are applicable for plants adopting NEDO-32291-A and/or Supplement 1.

However, the sensors for Functions 3 and 4 are allowed to be excluded from specific RPS RESPONSE TIME measurement if the conditions of Reference 12 are satisfied. If these conditions are satisfied, sensor response time may be allocated based on either assumed design sensor response time or the manufacturer's stated design response time. When the requirements of Reference 12 are not satisfied, sensor response time must be measured. Furthermore, measurement of the instrument loops response times for Functions 3 and 4 is not required if the conditions of Reference 13 are satisfied.] The RPS RESPONSE TIME acceptance criteria are included in Reference 11.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

RPS RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The 18 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

~~SR 3.3.1.1.16~~

~~This SR ensures that scrams initiated from OPRM Upscale Function (Function 2.f) will not be inadvertently bypassed when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is ≥[30]% RTP and core flow, as indicated by recirculation drive flow, is <[60]% rated core flow. This normally involves confirming the bypass setpoints. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. The actual surveillance ensures that the OPRM Upscale Function is enabled (not bypassed) for the correct values of APRM~~

SURVEILLANCE REQUIREMENTS (continued)

~~Simulated Thermal Power and recirculation drive flow. Other surveillances ensure that the APRM Simulated Thermal Power and recirculation flow properly correlate with THERMAL POWER and core flow, respectively.~~

~~If any bypass setpoint is nonconservative (i.e., the OPRM Upscale Function is bypassed when APRM Simulated Thermal Power ≥[30]% and recirculation drive flow <[60]% rated), then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the bypass setpoint may be adjusted to place the channel in a conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.~~

~~The Frequency of [18] months is based on engineering judgment and reliability of the components.~~

REFERENCES

1. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation."

2. FSAR, Figure [ ].

3. FSAR, Section [15.1.2].

4. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.

5. FSAR, Section [5.2.2].

6. FSAR, Section [15.1.38].

7. FSAR, Section [6.3.3].

8. FSAR, Chapter [15].

9. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.

10. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

11. FSAR, Table [7.2-2].

[12. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

13. NEDO-32291-A, Supplement 1, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1999.]

14. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function", October 1995.~~[March 1995].~~

15. ~~NEDO-31960-A, "BWR Owners' Group Long Term Stability Solutions Licensing Methodology," November 1995~~Not used.

16. ~~NEDO-31960-A, Supplement 1, "BWR Owners' Group Long Term Stability Solutions Licensing Methodology," November 1995~~Not used.

17. ~~NEDO-32465-A, "BWR Owners' Group Long Term Stability Detect and Suppress Solutions Licensing Basis Methodology And Reload Applications," [March 1996]~~Not used.

18. ~~Letter, LA England (BWROG) to MJ Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action", June 6, 1994~~Not used.

19. NEDC-33075P-A, Revision 6, "General Electric Boiling Water Reactor Detect and Suppress Solution - Confirmation Density," January 2008.

REFERENCES

20. GEH letter to NRC, "NEDC-33075P-A, Detect and Suppress Solution - Confirmation Density (DSS-CD) Analytical Limit (TAC No. MD0277)," October 29, 2008.

21. Amendment No. [159, "Issuance of Amendment Re: Request to Install Power Range Neutron Monitoring System," dated February 3, 2009. (ADAMS Accession No. ML083440681)]

22. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip. Function," November 1997.

APPENDIX B: EXAMPLE OF CHANGES TO BWR/4 STANDARD TECHNICAL SPECIFICATIONS – REVISION BAR VERSION

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR A.2 Place associated trip system in trip.	12 hours 12 hours
B. One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately

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ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < [30]% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1	Initiate action to implement the Manual BSP Regions defined in the COLR.	Immediately
	<u>AND</u>		
	I.2.1	Implement the Automated BSP Scram Region using the modified APRM flow-biased scram setpoints defined in the COLR.	12 hours
	<u>AND</u>		
	I.2.2	Initiate action in accordance with Specification 5.6.6.	90 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. Required Action and associated Completion Time of Condition I not met.	J.1 Initiate action to implement the Manual BSP Regions defined in the COLR. AND J.2 Reduce operation to below the BSP Boundary defined in the COLR. AND J.3 --------NOTE---------- LCO 3.0.4 is not applicable ---------------------- Restore required channel to OPERABLE	Immediately 12 hours 120 days
K. Required Action and associated Completion Time of Condition J not met.	K.1 [Reduce THERMAL POWER to less than [20]% RTP or Be in Mode 2].	[4 or 6] hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTES------------------------------------

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE	FREQUENCY
SR 3.3.1.1.1 Perform CHANNEL CHECK.	12 hours

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.2	------------------NOTE------------------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP [plus any gain adjustment required by LCO 3.2.4, "Average Power Range Monitor (APRM) Setpoints"] while operating at ≥ 25% RTP.	7 days
SR 3.3.1.1.3	Adjust the channel to conform to a calibrated flow signal.	7 days
SR 3.3.1.1.4	------------------NOTE------------------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.6	Calibrate the local power range monitors.	[1000] MWD/T average core exposure
SR 3.3.1.1.7	Perform CHANNEL FUNCTIONAL TEST.	[92] days
SR 3.3.1.1.8	[Calibrate the trip units.	[92] days]

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.6 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.9	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.10	Perform CHANNEL FUNCTIONAL TEST.	[18] months
SR 3.3.1.1.11	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	[18] months
SR 3.3.1.1.12	Verify the APRM Flow Biased Simulated Thermal Power - high time constant is ≤ [7] seconds.	[18] months
SR 3.3.1.1.13	Perform LOGIC SYSTEM FUNCTIONAL TEST.	[18] months
SR 3.3.1.1.14	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ [30]% RTP.	[18] months

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.15	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --- Verify the RPS RESPONSE TIME is within limits.	[18] months on a STAGGERED TEST BASIS

Table 3.3.1.1-1 (page 1 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	[3]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [120/125] divisions of full scale
	5(a)	[3]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [120/125] divisions of full scale
b. Inop	2	[3]	G	SR 3.3.1.1.4 SR 3.3.1.1.13	NA
	5(a)	[3]	H	SR 3.3.1.1.5 SR 3.3.1.1.13	NA
2. Average Power Range Monitors					
a. Neutron Flux — High, (Setdown)	2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.9 SR 3.3.1.1.13	≤ [20]% RTP
b. Flow Biased Simulated Thermal Power — High	1	[2]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [0.58 W + 62]% RTP and ≤ [115.5]% RTP(b) (c)

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) [0.58 W + 62% - 0.58 ΔW]RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) With OPRM Upscale (Function 2.f) inoperable, reset the APRM flow-biased setpoints to the values defined by the COLR to implement the Automated BSP Scram Region in accordance with Action I of this Specification.

Table 3.3.1.1-1 (page 2 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors					
c. Fixed Neutron Flux – High	1	[2]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [120]% RTP
[d. Downscale	1	[2]	F	SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13	≥ [3]% RTP
e. Inop	1,2	[2]	G	SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13	NA
f. OPRM Upscale	[≥ [20]% RTP or 1][(e)]	3[(c)]	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	NA
3. Reactor Vessel Steam Dome Pressure – High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [1054] psig
4. Reactor Vessel Water Level – Low, Level 3	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.15	≥ [10] inches
5. Main Steam Isolation Valve – Closure	1	[8]	F	SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [10]% closed
6. Drywell Pressure – High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [1.92] psig

(e) Following DSS-CD implementation, DSS-CD is not required to be armed while in the DSS-CD Armed Region during the first reactor startup and during the first controlled shutdown that passes completely through the DSS-CD Armed Region. However, DSS-CD is considered OPERABLE and shall be maintained OPERABLE and capable of automatically arming for operation at recirculation drive flow rates above the DSS-CD Armed Region.

Table 3.3.1.1-1 (page 3 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level — High					
a. Resistance Temperature Detector	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.1 SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
b. Float Switch	1,2	[2]	G	SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [57.15] gallons
8. Turbine Stop Valve - Closure	≥ [30]% RTP	[4]	E	SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≤ [10]% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ [30]% RTP	[2]	E	SR 3.3.1.1.7 [SR 3.3.1.1.8] SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ [600] psig
10. Reactor Mode Switch - Shutdown Position	1,2	[2]	G	SR 3.3.1.1.10 SR 3.3.1.1.13	NA
	5(a)	[2]	H	SR 3.3.1.1.10 SR 3.3.1.1.13	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

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Table 3.3.1.1-1 (page 4 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
11. Manual Scram	1,2	[2]	G	SR 3.3.1.1.5 SR 3.3.1.1.13	NA
	5[(a)]	[2]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

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5.6 Reporting Requirements

5.6.3 CORE OPERATING LIMITS REPORT

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

[The individual specifications that address core operating limits must be referenced here.]

[For DSS-CD, the following is required in addition to the normal list of limits:]

1. The Manual Backup Stability Protection (BSP) Scram Region (Region I), the Manual BSP Controlled Entry Region (Region II), [the modified APRM flow-biased setpoints used in the OPRM (Function 2.f), Automated BSP Scram Region, and the BSP Boundary] for Specification 3.3.1.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

[Identify the Topical Report(s) by number and title or identify the staff Safety Evaluation Report for a plant specific methodology by NRC letter and date. The COLR will contain the complete identification for each of the Technical Specification referenced topical reports used to prepare the COLR (i.e., report number, title, revision, date, and any supplements).]

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.4 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

[The individual specifications that address RCS pressure and temperature limits must be referenced here.]

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

[Identify the Topical Report(s) by number and title or identify the NRC Safety Evaluation for a plant specific methodology by NRC letter and date. The PTLR will contain the complete identification for each of the TS referenced Topical Reports used to prepare the PTLR (i.e., report number, title, revision, date, and any supplements).]

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5.6 Reporting Requirements

5.6.6 OPRM Report

When a report is required by Condition I of LCO 3.3.1.1, "RPS Instrumentation," a report shall be submitted within 90 days of entering CONDITION I. The report shall outline the preplanned means to provide backup stability protection, the cause of the inoperability, and the plans and schedule for restoring the required instrumentation channels to OPERABLE status.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

BWR/6 STS Note: The wording of the BASES descriptions of APRM Functions is somewhat different from the corresponding Functions for the BWR/4 ISTS to reflect slight differences in the architecture. However, the replacement text will be very similar to that shown in this example mark-up.

Average Power Range Monitor

2.a. Average Power Range Monitor Neutron Flux - High, Setdown

The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux - High, Setdown Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux - High, Setdown Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux - High Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux - High, Setdown Function will provide the primary trip signal for a corewide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux - High, Setdown Function. However, this Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed 25% RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < 25% RTP.

The APRM System is divided into two groups of channels with three APRM channel inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Neutron Flux - High, Setdown with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Average Power Range Monitor Neutron Flux - High, Setdown Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists. In MODE 1, the Average Power Range Monitor Neutron Flux - High Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events.

<u>2.b. Average Power Range Monitor Flow Biased Simulated Thermal Power - High</u>

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Fixed Neutron Flux - High Function Allowable Value. The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and protects the fuel cladding integrity by ensuring that the MCPR SL is not exceeded. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Fixed Neutron Flux - High Function will provide a scram signal before the Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function setpoint is exceeded.

The APRM System is divided into two groups of channels with four APRM inputs to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Flow Biased Simulated Thermal Power - High with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located. Each APRM channel receives two total drive flow signals representative of total core flow. The total drive flow signals are generated by four flow units, two of which supply signals to the trip system A APRMs, while the other two supply signals to the trip system B APRMs. Each flow unit signal is provided by summing up the flow signals from the two recirculation loops. To obtain the most conservative reference signals, the total flow signals from the two flow units (associated with a trip system as described above) are routed to a low auction circuit associated with each APRM. Each APRM's auction circuit selects the lower of the two flow unit signals for use as the scram trip reference for that particular APRM. Each required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channel only requires an input from one OPERABLE flow unit, since the individual APRM channel will perform the intended function with only one OPERABLE flow unit input. However, in order to maintain single failure criteria for the Function, at least one required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channel in each trip system must be capable of maintaining an OPERABLE flow unit signal in the event of a failure of an auction circuit, or a flow unit, in the associated trip system (e.g., if a flow unit is inoperable, one of the two required Average Power Range Monitor Flow Biased Simulated Thermal Power - High channels in the associated trip system must be considered inoperable).

The clamped Allowable Value is based on analyses that take credit for the Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function for the mitigation of the loss of feedwater heating event. The THERMAL POWER time constant of < 7 seconds is based on the fuel heat transfer dynamics and provides a signal proportional to the THERMAL POWER.

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, other IRM and APRM Functions provide protection for fuel cladding integrity.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.c. Average Power Range Monitor Fixed Neutron Flux - High

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The Average Power Range Monitor Fixed Neutron Flux - High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 5, the Average Power Range Monitor Fixed Neutron Flux - High Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 6) takes credit for the Average Power Range Monitor Fixed Neutron Flux - High Function to terminate the CRDA.

The APRM System is divided into two groups of channels with three APRM channels inputting to each trip system. The system is designed to allow one channel in each trip system to be bypassed. Any one APRM channel in a trip system can cause the associated trip system to trip. Four channels of Average Power Range Monitor Fixed Neutron Flux - High with two channels in each trip system arranged in a one-out-of- two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. In addition, to provide adequate coverage of the entire core, at least 11 LPRM inputs are required for each APRM channel, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

The Average Power Range Monitor Fixed Neutron Flux - High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Fixed Neutron Flux - High Function is assumed in the CRDA analysis, which is applicable in MODE 2, the Average Power Range Monitor Neutron Flux - High, Setdown Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Range Monitor Fixed Neutron Flux - High Function is not required in MODE 2.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.d. Average Power Range Monitor - Downscale

This signal ensures that there is adequate Neutron Monitoring System protection if the reactor mode switch is placed in the run position prior to the APRMs coming on scale. With the reactor mode switch in run, an APRM downscale signal coincident with an associated Intermediate Range Monitor Neutron Flux - High or Inop signal generates a trip signal. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The APRM System is divided into two groups of channels with three inputs into each trip system. The system is designed to allow one channel in each trip system to be bypassed. Four channels of Average Power Range Monitor - Downscale with two channels in each trip system arranged in a one-out-of- two logic are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal. The Intermediate Range Monitor Neutron Flux - High and Inop Functions are also part of the OPERABILITY of the Average Power Range Monitor - Downscale Function (i.e., if either of these IRM Functions cannot send a signal to the Average Power Range Monitor - Downscale Function, the associated Average Power Range Monitor - Downscale channel is considered inoperable).

The Allowable Value is based upon ensuring that the APRMs are in the linear scale range when transfers are made between APRMs and IRMs.

This Function is required to be OPERABLE in MODE 1 since this is when the APRMs are the primary indicators of reactor power.

2.e. Average Power Range Monitor - Inop

This signal provides assurance that a minimum number of APRMs are OPERABLE. Anytime an APRM mode switch is moved to any position other than "Operate," an APRM module is unplugged, the electronic operating voltage is low, or the APRM has too few LPRM inputs (< 11), an inoperative trip signal will be received by the RPS, unless the APRM is bypassed. Since only one APRM in each trip system may be bypassed, only one APRM in each trip system may be inoperable without resulting in an RPS trip signal. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Four channels of Average Power Range Monitor - Inop with two channels in each trip system are required to be OPERABLE to ensure that no single failure will preclude a scram from this Function on a valid signal.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

2.f. Oscillation Power Range Monitor (OPRM) Upscale

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

Reference [19] describes the Detect and Suppress - Confirmation Density (DSS-CD) long-term stability solution and the licensing basis Confirmation Density Algorithm (CDA). Reference [19] also describes the DSS-CD Armed Region and the three additional algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (PBDA), the amplitude based algorithm (ABA), and the growth rate algorithm (GRA). All four algorithms are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the CDA. The remaining three algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY is based only on the CDA.

The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms.

DSS-CD operability requires at least 8 responsive OPRM cells per channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is [at ≥20% RTP, which is established as a power level that is greater than or equal to 5% below the lower boundary of the Armed Region. This requirement is designed to encompass the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. The OPRM Upscale Function is automatically trip-enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is greater than or equal to 25% RTP corresponding to the plant-specific MCPR monitoring threshold and reactor recirculation drive flow, is less than [75 for MELLLA+ or 70 for MELLLA]% of rated flow.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

. This region is the OPRM Armed Region. Note e allows for entry into the DSS-CD Armed Region without automatic arming of DSS-CD prior to completely passing though the DSS-CD Armed Region during both a single startup and a single shutdown following DSS-CD implementation. Note e reflects the need for plant data collection in order to test the DSS-CD equipment. Testing the DSS-CD equipment ensures its proper operation and prevents spurious reactor trips. Entry into the DSS-CD Armed Region without automatic arming of DSS-CD during this initial testing phase also allows for changes in plant operations to address maintenance or other operational needs. However, during this initial testing period, the OPRM upscale function is OPERABLE and DSS-CD operability and capability to automatically arm shall be maintained at recirculation drive flow rates above the DSS-CD Armed Region flow boundary.

An OPRM Upscale trip is issued from an OPRM channel when the confirmation density algorithm in that channel detects oscillatory changes in the neutron flux, indicated by period confirmations and amplitude exceeding specified setpoints for a specified number of OPRM cells in the channel. An OPRM Upscale trip is also issued from the channel if any of the defense-in-depth algorithms (PBDA, ABA, GRA) exceed its trip condition for one or more cells in that channel.

Three of the four channels are required to be operable. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the MCPR SL is exceeded. There is no allowable value for this function.

The OPRM Upscale function settings are not traditional instrumentation setpoints determined under an instrument setpoint methodology. In accordance with the NRC Safety Evaluation for Amendment [159] (Ref. [21]), the OPRM Upscale Function is not LSSS SL-related and Reference 20 confirms that the OPRM Upscale Function settings based on DSS-CD also do not have traditional instrumentation setpoints determined under an instrument setpoint methodology.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Reactor Vessel Steam Dome Pressure - High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure - High Function initiates a scram for transients that results in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 5, reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Fixed Neutron Flux - High signal, not the Reactor Vessel Steam Dome Pressure - High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

High reactor pressure signals are initiated from four pressure transmitters that sense reactor pressure. The Reactor Vessel Steam Dome Pressure - High Allowable Value is chosen to provide a sufficient margin to the ASME Section III Code limits during the event.

Four channels of Reactor Vessel Steam Dome Pressure - High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the RCS is pressurized and the potential for pressure increase exists.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

There is no Allowable Value for this Function since the channels are mechanically actuated based solely on the position of the push buttons.

Four channels of Manual Scram with two channels in each trip system arranged in a one-out-of-two logic are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

------------------------REVIEWER'S NOTE---------------------

Certain LCO Completion Times are based on approved topical reports. In order for a licensee to use the times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.

A Note has been provided to modify the ACTIONS related to RPS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

<u>A.1 and A.2</u>

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 10) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip

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ACTIONS (continued)

system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 10 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 10, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

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ACTIONS (continued)

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram [or RPT]), Condition D must be entered and its Required Action taken.

<u>C.1</u>

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 8 (Turbine Stop Valve--Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

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ACTIONS (continued)

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1, F.1, and G.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Action E.1 is consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

I.1

If OPRM Upscale trip capability is not maintained, Condition I exists and Backup Stability Protection (BSP) is required. The Manual BSP Regions are described in Reference [19]. The Manual BSP Regions are procedurally established consistent with the guidelines identified in Reference [19] and require specified manual operator actions if certain predefined operational conditions occur.

ACTIONS (continued)

The Completion Time of immediate is based on the importance of limiting the period of time during which no automatic or alternate detect and suppress trip capability is in place.

I.2.1 and I.2.2

Actions I.2.1 and I.2.2 are both required to be taken in conjunction with Action I.1 if OPRM Upscale trip capability is not maintained. As described in Section 7.4 of Reference [19], the Automated BSP Scram Region is designed to avoid reactor instability by automatically preventing entry into the region of the power and flow-operating map that is susceptible to reactor instability. The reactor trip would be initiated by the modified APRM flow-biased scram setpoints for flow reduction events that would have terminated in the Manual BSP Region I. The Automated BSP Scram Region ensures an early scram and SLMCPR protection.

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, and based on the importance of restoring an automatic reactor trip for thermal hydraulic instability events.

Backup Stability Protection is intended as a temporary means to protect against thermal-hydraulic instability events. The reporting requirements of Specification 5.6.6 document the corrective actions and schedule to restore the required channels to an OPERABLE status. The Completion Time of 90 days is adequate to allow time to evaluate the cause of the inoperability and to determine the appropriate corrective actions and schedule to restore the required channels to OPERABLE status.

J.1

If the Required Actions I are not completed within the associated Completion Times, then Action J is required. The Bases for the Manual BSP Regions and associated Completion Time is addressed in the Bases for I.1. The Manual BSP Regions are required in conjunction with the BSP Boundary.

J.2

The BSP Boundary, as described in Section 7.3 of Reference [19], defines an operating domain where potential instability events can be effectively addressed by the specified BSP manual operator actions. The BSP Boundary is constructed such that the immediate final statepoint for a flow reduction event initiated from this boundary and terminated at the core

ACTIONS (continued)

natural circulation line (NCL) would not exceed the Manual BSP Region I stability criterion. Potential instabilities would develop slowly as a result of the feedwater temperature transient (Reference [19]).

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, to reach the specific condition from full power conditions in an orderly manner and without challenging plant system.

J.3

Backup Stability Protection (BSP) is a temporary means for protection against thermal-hydraulic instability events. An extended period of inoperability without automatic trip capability is not justified. Consequently, the required channels are required to be restored to OPERABLE status within 120 days.

Based on engineering judgment, the likelihood of an instability event that could not be adequately handled by the use of the BSP Regions (See Action J.1) and the BSP Boundary (See J.2) during a 120-day period is negligibly small. The 120-day period is intended to allow for the case where limited design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. This action is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to normally be accomplished within the completion times allowed for Actions for Conditions A and B.

A Note is provided to indicate that LCO 3.0.4 is not applicable. The intent of that note is to allow plant startup while operating within the 120-day Completion Time for Required Action J.3. The primary purpose of this exclusion is to allow an orderly completion of design and verification activities, in the event of a required design change, without undue impact on plant operation.

ACTIONS (continued)

K.1

If the required channels are not restored to OPERABLE status and the Required Actions of J are not met within the associated Completion Times, then the plant must be placed in an operating condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least [20% RTP or Mode 2] within [4 or 6] hours. The allowed Completion Time is reasonable, based on operating experience, to reach the specified operating power level from full power conditions in an orderly manner and without challenging plant systems.

------------------------REVIEWER'S NOTE---------------------
Certain Frequencies are based on approved topical reports. In order for a licensee to use these Frequencies, the licensee must justify the Frequencies as required by the staff SER for the topical report.

SURVEILLANCE REQUIREMENTS (continued)

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column ofTable 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 4) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

SR 3.3.1.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The agreement criteria includes an expectation of one decade of overlap when transitioning between neutron flux instrumentation. The overlap between SRMs and IRMs must be demonstrated prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from the SRMs to the IRMs. This will ensure that reactor power will not be increased into a neutron flux region without adequate ndication. The overlap between IRMs and APRMs is of concern when reducing power into the IRM range (entry into MODE 2 from MODE 1). On power

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SURVEILLANCE REQUIREMENTS (continued)

increases, the system design will prevent further increases (by initiating a rod block) if adequate overlap is not maintained. Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have onscale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block or IRM upscale rod block. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above mid-scale on Range 1 before SRMs have reached the upscale rod block.

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channels(s) declared inoperable. Only those appropriate channels that are required in the current MODE or condition should be declared inoperable.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

<u>SR 3.3.1.1.2</u>

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoints," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of calculated MFLPD. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.6.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). At 25% RTP, the

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS (continued)

Surveillance is required to have been satisfactorily performed within the last 7 days, in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function uses the recirculation loop drive flows to vary the trip setpoint. This SR ensures that the total loop drive flow signals from the flow units used to vary the setpoint is appropriately compared to a calibrated flow signal and, therefore, the APRM Function accurately reflects the required setpoint as a function of flow. Each flow signal from the respective flow unit must be ≤ 105% of the calibrated flow signal. If the flow unit signal is not within the limit, one required APRM that receives an input from the inoperable flow unit must be declared inoperable.

The Frequency of 7 days is based on engineering judgment, operating experience, and the reliability of this instrumentation.

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS (continued)

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 9).

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. In accordance with Reference 10, the scram contacts must be tested as part of the Manual Scram Function. A Frequency of 7 days provides an acceptable level of system average availability over the Frequency and is based on the reliability analysis of Reference 11. (The Manual Scram Function's CHANNEL FUNCTIONAL TEST Frequency was credited in the analysis to extend many automatic scram Functions' Frequencies.)

SR 3.3.1.1.6

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The [1000] MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.6 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.7 and SR 3.3.1.1.10

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.7 is based on the reliability analysis of Reference 10.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.8

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 10.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.9 and SR 3.3.1.1.11

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the [1000] MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.6). A second Note is provided that requires the APRM and IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

The Frequency of SR 3.3.1.1.9 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis (Ref. 22). The Frequency of SR 3.3.1.1.11 is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.12

The Average Power Range Monitor Flow Biased Simulated Thermal Power - High Function uses an electronic filter circuit to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This filter circuit is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The Surveillance filter time constant must be verified to be ≤ 7 seconds to ensure that the channel is accurately reflecting the desired parameter.

The Frequency of 18 months is based on engineering judgment considering the reliability of the components.

NOTE: The addition of “[ ]” around the 1000 MWD/T in SR 3.3.1.1.9 and SR 3.3.1.1.11 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.13

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.14

This SR ensures that scrams initiated from the Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ 30% RTP to ensure that the calibration remains valid.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.15

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements.

[----------------------REVIEWER'S NOTE--------------------------
The following Bases are applicable for plants adopting NEDO-32291-A and/or Supplement 1.

However, the sensors for Functions 3 and 4 are allowed to be excluded from specific RPS RESPONSE TIME measurement if the conditions of Reference 12 are satisfied. If these conditions are satisfied, sensor response time may be allocated based on either assumed design sensor response time or the manufacturer's stated design response time. When the requirements of Reference 12 are not satisfied, sensor response time must be measured. Furthermore, measurement of the instrument loops response times for Functions 3 and 4 is not required if the conditions of Reference 13 are satisfied.] The RPS RESPONSE TIME acceptance criteria are included in Reference 11.

As noted, neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.

RPS RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The 18 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

SURVEILLANCE REQUIREMENTS (continued)

REFERENCES

1. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation."

2. FSAR, Figure [ ].

3. FSAR, Section [15.1.2].

4. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.

5. FSAR, Section [5.2.2].

6. FSAR, Section [15.1.38].

7. FSAR, Section [6.3.3].

8. FSAR, Chapter [15].

9. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.

10. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

11. FSAR, Table [7.2-2].

[12. NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1995.

13. NEDO-32291-A, Supplement 1, "System Analyses for the Elimination of Selected Response Time Testing Requirements," October 1999.]

14. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function", October 1995.

15. Not used.

16. Not used.

17. Not used.

18. Not used.

19. NEDC-33075P-A, Revision 6, "General Electric Boiling Water Reactor Detect and Suppress Solution - Confirmation Density," January 2008.

REFERENCES

20. GEH letter to NRC, "NEDC-33075P-A, Detect and Suppress Solution - Confirmation Density (DSS-CD) Analytical Limit (TAC No. MD0277)," October 29, 2008.

21. Amendment No. [159, "Issuance of Amendment Re: Request to Install Power Range Neutron Monitoring System," dated February 3, 2009. (ADAMS Accession No. ML083440681)]

22. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip. Function," November 1997.

APPENDIX C

GEH Responses to NRC RAIs on NEDC-33075P Revision 7

RAI-01:

The TRACG demonstration matrix relies on modeling the oscillation power range monitor (OPRM) response, which is obtained from the calculated local power range monitor (LPRM) time traces. Please provide a reference to how TRACG models the LPRM detectors and any available benchmarks.

GEH Response:

TRACG solves the three-dimensional (3-D) transient neutron diffusion equation using the same basic formulation and assumptions as in PANACEA (References 1-1 and 1-2). The core is described using i, j, k nomenclature, where i and j indices define the location of each flow channel and the k index provides the axial location. TRACG simulates the LPRM signal through the use of the control system input/output variables (Reference 1-1). The i, j, and k location of the LPRM detector is specified in the TRACG input. The LPRM signal is the TRACG calculated average nodal fission power of the 8 surrounding kinetics nodes to the specified i, j, and k location of the LPRM detector (4 above and 4 below the specified location).

Extensive comparisons of the LPRM, average power range monitor (APRM) and/or oscillation power range monitor (OPRM) plant data and validation of TRACG results were provided in Reference 1-3 for the Peach Bottom turbine trip tests, LaSalle instability event, Leibstadt stability tests, and the Nine Mile Point 2 instability event.

In addition, algorithm and LPRM/OPRM testing is documented in Tables 5-5 and 5-6 of the approved Detect and Suppress Solution – Confirmation Density (DSS-CD) licensing topical report (LTR, Reference 1-4). Testing of the application to OPRM cells was performed in support of the algorithm qualifications and is also summarized in Table 5-5 of Reference 1-4. These tests include Pilgrim stable startup data and KKL instability event data. Multiple LPRM signals from the KKL Cycle 7 regional instability test event and Columbia Cycle 8 core-wide instability event (see Table 5-6 in Reference 1-4) were examined and validated as documented in Section 5.3.2 of Reference1-4. These results were reviewed and approved in Revision 6 of DSS-CD LTR (Reference 1-4) and apply to Revision 7 of the DSS-CD LTR as well (Reference 1-5).

References:

1-1. GE Hitachi Nuclear Energy, "TRACG Model Description," NEDE-32176P, Revision 4, January 2008.

1-2. GE Nuclear Energy, "Steady-State Nuclear Methods," NEDE-30130P-A, April 1985.

1-3. GE Hitachi Nuclear Energy, "TRACG Qualification," NEDE-32177P, Revision 3, August 2007.

1-4. GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P-A, Revision 6, January 2008.

1-5. GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P, Revision 7, June 2011.

RAI-02:

Section 4.7.2 of NEDC-33075P states that [[

]]. The wording appears to be misleading because additional analyses are required if the applicability checklist is not satisfied. Please specify under which circumstances the full analysis matrix is required.

GEH Response:

Additional analyses are required each time the applicability checklists in Tables 4-1 and 4-6 of Reference 2-1 are not satisfied. The full analysis matrix of cases is required for a plant with [[

]] The full analysis matrix includes the following [[

]]

The statement in Section 4.7.2 of NEDC-33075P (Reference 2-1) refers only to the [[

]]

The reason for this approach is described in Section 4.7.2 of Reference 2-1; [[

]]

References:

2-1. GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P, Revision 7, June 2011.

2-2. GE Hitachi Nuclear Energy, "General Electric Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P-A, Revision 6, January 2008.

RAI-03:

Please define the term "RS" and its units in the figure on page 4-27 labeled "OPRM Cell 121."

GEH Response:

'RS' in the figure on page 4-27 (Reference 3-1) is a normalized signal without units. Figure 4-9 in Reference 3-1 depicts [[

]] Therefore, 'Cn' is the same as 'RS' in the figure on page 4-27, a normalized signal without units.

A short explanation about the meaning and units of RS will be added in the figure on page 4-27 from NEDC-33075P Revision 7 (Reference 3-1) when the accepted (-A) version is published.

References:

3-1. GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P, Revision 7, June 2011.

RAI-04:

In the table on page 4-28, the fourth column is labeled [[ ]] However, only one margin value is presented in the table, which appears to be the TLO margin. Please explain. Please [[ ]] in the third column of this table.

GEH Response:

In the table on page 4-28 of Reference 4-1, one [[ ]] margin value is provided, but depending on the scenario the margin is either related to the Two Loop Operation (TLO) Safety Limit Minimum Critical Power Ratio (SLMCPR) or the Single Loop Operation (SLO) SLMCPR. The first [[ ]] Therefore, the table on page 4-28 is correct and consistent with the description provided in Step 4 on page 4-28 (Reference 4-1).

The [[ ]]

References:

4-1. GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P, Revision 7, June 2011.

RAI-05:

In the table on page 4-29, the fifth column is labeled [[ ]]. Since NEDC-33075P is the DSS-CD LTR, this statement is somewhat confusing. Does this mean [[ ]]? Would a restriction on initial MCPR/operating limit MCPR (IMCPR/OLMCPR) be imposed if the "Plant X" margins were lower than the "Matrix" margins?

GEH Response:

In the table on page 4-29 (Reference 5-1), the fifth column labeled [[

]]

No restriction would be imposed on Initial MCPR (IMCPR) / Operating Limit MCPR (OLMCPR) in the instance in which "Plant X" [[ ]] margins were lower than the "Matrix" [[ ]] margins provided in the Detect and Suppress Solution – Confirmation Density (DSS-CD) Licensing Topical Report (LTR, Reference 5-1). However, as specified in Step 5 on page 4-28 of Reference 5-1, the [[

]]

References:

5-1. GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P, Revision 7, June 2011.

RAI-06:

Step 7 on page 4-29 is confusing. It refers to an "MCPR criterion." However, Table 4-15 provides [[ ]] It is not clear from the text in Step 7 how plant X satisfies this criterion. Do the criteria in Table 4-15 [[ ]]? Please explain Step 7 in more detail.

GEH Response:

Table 4-15 in Reference 6-1 provides [[ ]]

The demonstration of how "Plant X" satisfies this criterion is actually described in Step 8 on pages 4-30 and 4-31 in Reference 6-1. In the example presented in Step 7 on pages 4-29 and 4-30 in Reference 6-1, the [[ ]]

This is shown for Step 8 in the seventh row/third column in the table on page 4-31 (Reference 6-1). [[ ]] and the result is shown in Step 8 in the eight row/third column in the table on page 4-31 (Reference 6-1).

Therefore, the criteria in Table 4-15 [[ ]]

References:

6-1. GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P, Revision 7, June 2011.

RAI-07:

In Table 3-4, the period based detection algorithm setpoint (S_p) value in row 2, column 3 is marked as proprietary; however, on page 3-24, the same formula for S_p is not marked as proprietary. Please provide the correct proprietary marking. Additionally, for this S_p value in Table 3-4, the "max" function is missing the closing parenthesis.

GEH Response:

The formula for S_p on page 3-24 (Reference 7-1) is proprietary and needs to be marked as such, consistent with Table 3-4 proprietary markings. Therefore, this formula will be corrected and marked as proprietary on page 3-24 in NEDC-33075P Revision 7 (Reference 7-1) when the accepted (-A) version is published.

The S_p formula in row 2, column 3 of Table 3-4 (Reference 7-1) is missing the closing parenthesis. Therefore, this formula in row 2, column 3 of Table 3-4 will be corrected in NEDC-33075P Revision 7 (Reference 7-1) to include the closing parenthesis when the accepted (-A) version is published.

References:

7-1 GE Hitachi Nuclear Energy, "GE Hitachi Boiling Water Reactor Detect and Suppress Solution – Confirmation Density (DSS-CD)," NEDC-33075P, Revision 7, June 2011.