WCAP-15981-NP, Rev 0 (Non-Proprietary)
Project No. 694

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WOG-06-104

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

Subject: Pressurized Water Reactor Owners Group
Responses to the NRC Request for Additional Information (RAI) Regarding the Review of WCAP-15981-NP, "Post Accident Monitoring Instrumentation Re-Definition for Westinghouse NSSS Plants," (LSC-0072 R1/MUHP-3038)

In September 2004, the Pressurized Water Reactor Owners Group (PWROG) (formerly the Westinghouse Owners Group) submitted WCAP-15981-NP (Non-Proprietary), Rev. 0, "Post Accident Monitoring Instrumentation Redefinition for Westinghouse NSSS Plants" for review and approval (Ref. 1). In April 2005 and May 2005, the NRC provided Requests for Additional Information (RAIs) for WCAP-15981 (Ref. 2, 3 and 4). Attachment1 to this letter provides the RAI responses and Attachment 2 provides the changes to WCAP-15981 based on the RAI responses. As noted in the very last RAI response in Attachment 1, the PAM Technical Specification mark-ups will be provided to the NRC by April 14, 2006. Following receipt of the Safety Evaluation for WCAP-15981, the WCAP changes contained in Attachment 2 will be incorporated into the approved version and will be issued as WCAP-15981-NP-A, Revision 1.

It should be noted that these RAI responses and WCAP markups being transmitted are identical to the draft RAI responses and WCAP mark-ups that were provided to the NRC on November 15, 2005 (Ref. 5). Per the NRC/WOG monthly Topical Report status call on February 21, 2006, the NRC (G. Shukla) indicated that the Staff had no comments on the draft RAI draft responses and the WCAP mark-ups, and requested that the PWROG formally submit the RAI responses and WCAP mark-ups to the NRC.

These RAI responses and WCAP mark-ups are being provided to support issuance of the draft Safety Evaluation for WCAP-15981 by August 1, 2006 which is consistent with the current Topical Report schedule on the NRC Topical Report web page and the latest communication from the NRC (G. Shukla) to the PWROG PM.

DO48

If you have any questions concerning this matter, please feel free to call Tom Laubham at 412-374-6788.

Sincerely yours,

Frederick P. "Ted" Schiffley, II, Chairman
Pressurized Water Reactor Owners Group

FPS:TJL:mjl

Attachments

cc: Licensing Subcommittee
Steering Committee
R. A. Gramm, NRC
G. S. Shukla, NRC (via FedEx)
J. D. Andrachek
K. Vavrek
J. Duryea
C. B. Brinkman
J. A. Gresham
PMO

References:

1. WOG Letter, F. Schiffley to Document Control Desk, "Transmittal of WCAP-15981-NP (Non-Proprietary), Rev. 0, 'Post Accident Monitoring Instrumentation Redefinition for Westinghouse NSSS Plants'," WOG-02-474, September 17, 2004.

2. NRC E-Mail, G. Shukla to S. DiTommaso, "RAIs on WCAP-15981 - Post Accident Monitoring Instrumentation Re-Definition," April 11, 2005.

3. NRC E-Mail, G. Shukla to S. DiTommaso, "I&C RAIs on WCAP-15981, 'Post Accident Monitoring Instrumentation Re-definition for Westinghouse NSSS Plants'," May 16, 2005.

4. NRC E-Mail, G. Shukla to S. DiTommaso, "RAIs on WCAP-15981, Post Accident Monitoring Instrumentation Redefinition " May 26, 2005.

5. WOG E-Mail, T. Laubham to G. Shukla, "Draft RAI Responses and WCAP-15981 Markups,' November 15, 2005.

Attachment 1

Response to Request for Additional Information Regarding WCAP-15981, "Post Accident Monitoring Instrumentation Re-Definition for Westinghouse NSSS Plants"

PLANT SYSTEMS BRANCH RAIs
(Received April 11, 2005 via an e-mail from G. Shukla (NRC) to S. DiTommaso (W))

General Comments:

1. Generic insights from the Westinghouse PRA database are useful, but potentially incomplete, e.g., the database does not reflect risk achievement worth (RAW) rankings based on the latest plant-specific PRA results, plant-specific details regarding the relationship between important operator actions and associated instrumentation, and the resolution of peer review comments. Although generic risk insights could be used in a limited manner, i.e., to add instruments to the standard technical specification, additional assessments at a plant-specific level would be required if instruments are to be removed from technical specifications on the basis of risk. The discussion on methodology implementation needs to better describe the plant-specific risk assessments that are expected to be performed by the utility, and the manner in which the results of these assessments are to be used in the implementation process.

Response:

The significant operator actions, determined by risk importance will be determined from the plant specific PRA when WCAP-15981 is implemented on a plant-specific basis to identify the instrumentation utilized for those operator actions. The generic risk insights were only utilized to identify the key operator actions based on risk importance in the generic methodology and are used to develop the proposed generic PAM Technical Specification contained in NUREG-1431. The plant specific PAM instrumentation will be determined utilizing the plant specific PRA.

WCAP-15981 Sections 3.1, 4.6, 5, 7, and 8 were revised to clarify that the plant specific PRA will be utilized to determine the plant specific PAM instrumentation and the scope and technical adequacy of the PRA information used in the determination.

(The revisions to Sections 3.1, 4.6, 5, 7, and 8 are provided in Attachment 2.)

2. The conclusion of the study regarding the specific instruments that should be added to or removed from the PAM technical specification appears to have been based largely on a qualitative, reclassification of the key instruments (as summarized in Tables 10 and 11) rather than on the basis of the importance of the instrumentation to risk, EOPs, or other factors. Thus, this methodology does not appear to be "risk-informed", and should not be characterized as such. If the report is modified to more clearly de-emphasize the role of risk information in supporting the conclusions, certain information/assessments requested below may not be needed.

Response:

The plant instrumentation was evaluated with respect to the Criteria of 10 CFR 50.36, specifically Criterion 3 and Criterion 4, which are the only criteria applicable to the identifying Post Accident Monitoring (PAM) instrumentation that should be included in the Technical Specifications.

The Emergency Operating Procedures (EOPs) were used in the methodology contained in WCAP-15981 to determine the instrumentation that is utilized to perform specific manual actions assumed in the DBA analyses for which there is no automatic actuation of equipment provided. The instrumentation utilized in the EOPs to cue specific manual actions that are assumed in the DBA analyses satisfies Criterion 3 of 10 CFR 50.36, and should be included in the PAM Technical Specification.

The plant instrumentation was also evaluated in WCAP-15981 from a risk perspective based on risk insights obtained from the PRA in terms of the important operator actions identified based on risk importance. Also included under the broad category of risk insights is the use of instrumentation in the Severe Accident Management Guidance (SAMG), and Emergency Plan Implementing Procedures (EPIP). If the plant instrumentation was shown to be important to risk mitigation in the PRA, SAMG, or EPIP, it is concluded that it satisfies Criterion 4 of 10 CFR 50.36 and should be included in the PAM Technical Specification. Therefore risk insights were used solely for the purpose of identifying the instrumentation that satisfied Criterion 4 of 10 CFR 50.36.

The Regulatory Guide 1.97 reclassification of the instrumentation was performed to reflect how the instrumentation is currently utilized in accident management, as opposed to the classification identified when the original plant specific Regulatory Guide 1.97 evaluations were performed. For consistency, the Regulatory Guide 1.97 classification should be consistent with the instrumentation proposed to be included in the PAM Technical Specification. As discussed above, Criteria 3 and 4 of 10 CFR 50.36 were utilized to determine whether the instrumentation should be included in the PAM Technical Specification, not the Regulatory Guide 1.97 reclassification of the instrumentation.

Instrumentation that satisfies Criterion 3 of 10 CFR 50.36 should be classified as Regulatory Guide 1.97 Type A instrumentation. Instrumentation that satisfies Criterion 4 of 10 CFR 50.36 should be classified as Regulatory Guide 1.97 Category I instrumentation. All other instrumentation not included in the PAM Technical Specification should have a lower Regulatory Guide 1.97 classification.

WCAP-15981 Section 3.2 and Appendix A were revised to clarify that the proposed approach is not risk informed in accordance with Regulatory Guide 1.174, but rather uses PRA insights and other applicable information in determining the instrumentation that should be included in the PAM Technical Specification.

(The revisions to Sections 3.2 and Appendix A are provided in Attachment 2.)

3. The addition of three instruments to the PAM technical specification in accordance with the topical report conclusions (steam generator pressure, refueling water storage tank level, and high head safety injection flow) is consistent with the importance of these instruments in DBAs, EOPs, PRAs, as well as other applications, such as the Emergency Response Data

System (ERDS). (Although the conclusion appears to have been based on a reclassification of these instruments, rather than on the importance of the instrumentation to risk, etc., as stated above.) Accordingly, the NRC staff would concur with this conclusion.

Response:

No response required, the Staff agrees with adding these instruments to the PAM Technical Specification.

4. Five of the six instruments that would be relocated from the PAM technical specification in accordance with the topical report conclusions (source range neutron flux, RCS hot and cold leg temperature, reactor vessel water level, and containment sump water level) are significant in EOPs, EALs, and SAMG, as well as required parameters for ERDS. (Again, the conclusion appears to have been based on a reclassification of these instruments, rather than on the importance of the instrumentation to EOPs, etc.). The justification for removing these instruments from the PAM technical specification appears inadequate, given the role of these instruments as potentially-important indicators of plant status and event progression.

Response:

See the response to General Comment RAI Number 2 above regarding the Regulatory Guide 1.97 reclassification of the instrumentation and evaluation of the instrumentation with respect to Criteria 3 and 4 of 10 CFR 50.36 to determine whether it should be included in the PAM Technical Specification.

There are two types of instrumentation utilized in the EOPs, PRA, SAMG, and EPIP; "key" instrumentation that is necessary for the operator to effectively diagnose, and mitigate accidents, and "backup" instrumentation that supplements the "key" instrumentation that supports operator actions to recover the plant.

The "key" instrumentation provides the primary information required to permit the control room operating staff to:

- Perform the diagnosis, in accordance with the plant EOPs, of plant conditions required to initiate manual actions required to bring the plant to a safe stable state for DBAs (discussed in the UFSAR) as well as the wider range of potential accident sequences included in the PRA,
- Perform the pre-planned manual actions in accordance with the plant EOPs, for which no automatic control is provided, that are required for safety systems to accomplish their safety function to mitigate DBAs,
- Perform the pre-planned manual actions in accordance with the plant EOPs to bring the plant to a safe stable state for a wide range of accidents included in the PRA, and
- Diagnose plant conditions that may pose a threat to the health and safety of the general public in accordance with the plant SAMG and EPIP.

The "backup" instrumentation permits the control room operating staff to:

- Verify the indications of the key instrumentation,
- Operate plant systems utilized to achieve a safe shutdown, including the verification of the automatic actuation of safety systems, and
- Operate other systems normally utilized for achieving a safe shutdown condition.

The instrumentation utilized in the EOPs to cue operator actions for which no automatic control is provided satisfies Criteria 3 of 10 CFR 50.36. All other plant instrumentation was evaluated from a risk perspective based on its use in the PRA, SAMG, and EPIP, to determine whether it satisfies Criteria 4 of 10 CFR 50.36. If the instrumentation does not satisfy Criteria 3 or 4 of 10 CFR 50.36, it can be relocated out of the PAM Technical Specification to a licensee controlled document.

The ERDS is covered by another regulation, Appendix E to 10 CFR 50, and is not affected by the evaluation of the PAM instrumentation with respect to Criterion 3 or 4 of 10 CFR 50.36. If instrumentation that is required by Appendix E to 10 CFR 50 for ERDS does not satisfy Criterion 3 or 4 of 10 CFR 50.36, it should not be included in the PAM Technical Specification. While ERDS provides a significant amount of information to the NRC, and may provide information to other licensee offsite facilities, it is not used directly by the plant operators in their role in mitigating the consequences of an accident.

Specific Information Requests:

1. The assessment of PAM instrumentation considered instrumentation important to design basis accidents (DBAs), probabilistic risk assessments (PRAs), emergency operating procedures (EOPs), severe accident management guidance (SAMG), and Emergency Plan Implementing Procedures (EPIPs), but failed to consider those parameters that are required to be transmitted to the NRC via the Emergency Response Data System (ERDS). Although ERDS is not a safety system, consideration of these parameters within the topical report framework would provide additional insights into a decision on whether certain instruments should be added to or removed from technical specifications. Please expand the assessment to include consideration of the ERDS parameters, and reassess the recommendations for relocation of certain instrumentation in view of the role of these instruments in ERDS.

Response:

The ERDS is covered by another regulation, Appendix E to 10 CFR 50, and is not affected by the evaluation of the PAM instrumentation with respect to Criterion 3 or 4 of 10 CFR 50.36. If instrumentation that is required by Appendix E to 10 CFR 50 for ERDS does not satisfy Criterion 3 or 4 of 10 CFR 50.36, it should not be included in the PAM Technical Specification. While ERDS provides a significant amount of information to the NRC, and may provide information to other licensee offsite facilities, it is not used directly by the plant operators in their role in mitigating the consequences of an accident.

2. Several instruments are listed in Table 4 but not included in Table 9, e.g., auxiliary feedwater valve position, containment water level (wide range), residual heat removal flow. Also, high

head safety injection is identified in Table 9 but not in Table 4. Please update the tables so they are consistent.

Response:

WCAP-15981 Table 9 was revised to include all of the instruments that are contained in Table 4. Table 4 was revised to include High Head SI Flow.

(The revisions to Tables 4 and 9 are provided in Attachment 2.)

3. In Table 5, it is stated that high risk significance is defined from CDF and LERF risk achievement and risk reduction metrics per Regulatory Guide (RG) 1.174. Although the RG discusses importance measures, it does not define specific values for these metrics for screening purposes. Please provide a more appropriate reference for the selected screening values.

Response:

WCAP-15981 Section A.4 was revised to reference the EPRI PSA Application Guide, NEI-00-04, and Regulatory Guide 1.201 on the use of risk importance measures to determine risk important systems, structures and components.

(The revisions to Section 8 and Appendix A.4 are provided in Attachment 2.)

4. The identification of risk-significant operator actions is based on PRA information compiled within the proprietary Westinghouse PRA database. Please provide a general description of this database, including the type of information contained in the database, the number of plants represented (e.g., total, by RCS design, by containment type), and the vintage/pedigree of the data (e.g., the portion of the data that is based on IPEs, pre-peer-reviewed updates of the IPE, and post-peer-reviewed updates that address peer review findings). Identify and describe any previous applications where insights/results from this database were also used to support the application.

Response:

The PAM instrumentation proposed to be included in Technical Specification 3.3.3, "PAM Instrumentation," of NUREG-1431 was determined based on generic insights obtained from the Westinghouse NSSS PRA database. The PAM instrumentation that will be included in the plant specific PAM Technical Specifications will be determined utilizing the plant specific PRA to determine the plant specific risk significant operator actions. The Westinghouse NSSS PRA database was only used for demonstrative purposes to identify the instrumentation that would be included in the PAM Technical Specification for a generic, reference plant.

WCAP-15981 Sections 7 and 8 were revised to clarify that the plant specific PRA will be utilized to determine the plant specific PAM instrumentation that should be included in the PAM Technical Specification.

(The revisions to Sections 7 and 8 are provided in Attachment 2.)

5. Please explain why operator actions related to prevention of reactor coolant pump (RCP) seal LOCAs are not among the set of important operator actions identified in Appendix A, given the large contribution to core damage frequency from RCP seal LOCA sequences in some Westinghouse plant PRAs, including those employing the latest ("WOG 2000") seal LOCA methodology.

Response:

Although reactor coolant pump (RCP) seal LOCAs are an important contributor to core damage for Westinghouse PWRs, there are no operator actions modeled in the PRA to protect the RCPs from a seal LOCA. The plant specific abnormal/off-normal procedures provide guidance for restoring RCP seal cooling for those sequences that are susceptible to RCP seal LOCAs (which are sequences involving a loss of all RCP seal cooling). However, if RCP seal cooling is not quickly re-established, then the abnormal/off-normal procedures typically instruct the operators not to re-establish RCP seal cooling in order to avoid additional RCP seal damage due to thermal shock. The preferred recovery strategy in this case is to use an aggressive RCS cooldown to cool down the RCP seals. The time available for restoration of RCP seal cooling is very short (e.g., on the order of minutes) and therefore recovery from a loss of RCP seal cooling event for accident initiators modeled in the PRA is very unlikely. The PRA modeling of a recovery from a loss of RCP seal cooling does not include the diagnosis of the loss of RCP seal cooling and the subsequent unique recovery strategies; the nominal strategy to bring the plant to a safe stable state would provide an adequate RCP seal cool down. Thus, there are no risk significant operator actions for preventing an RCP seal LOCA.

WCAP-15981 Section A.5 was revised to include a discussion of RCP seal LOCAs.

(The revisions to Section A.5 are provided in Attachment 2.)

6. Section 4.2 provides a list of instruments determined from the PRA to be important for preventing core damage. However, this list does not include several additional instruments that are indicated as important to risk in Table 7, i.e., containment sump water level (wide range), containment pressure (wide range), containment isolation valve position, and component cooling water flow rate. The list/section also does not include several instruments important to LERF, as discussed in Appendix A, e.g., core exit temperature and containment isolation valve position indication. Please provide a more complete accounting and discussion of the risk-significant instruments.

Response:

The instruments listed in Section 4.2 on page 15 are the same instruments that are listed in Appendix A on page A-11. These instruments are risk important in the PRA to cue operator actions necessary to prevent core damage. Tables 7 and 8 were revised to be consistent with Appendix A and Section 4.2. Appendix A also discusses several operator actions that can be important to risk but for which there is no unique set of instrumentation to cue the diagnosis and subsequent implementation of recovery strategies.

The instruments that were determined to be important to cue operator actions to prevent large early releases, as discussed in Appendix A are:

- Core Exit Temperature
- RCS Pressure
- Steam Generator Level
- Containment Isolation Valve Position
- Containment Pressure

The above instruments are included in Table 7 to show their risk importance.

WCAP-15981 Section 4.2 was revised to include a discussion of LERF that is contained on pages A-11 to A-13 of Appendix A.

(The revisions to Section 4.2 and Tables 7 and 8 are provided in Attachment 2.)

7. The identification of risk-significant operator actions and associated instrumentation is based exclusively on consideration of the Westinghouse database/survey for internally-initiated at-power events. Although the impact of externally-initiated events on instrument identification is addressed qualitatively in Appendix A, it appears that no consideration has been given to instrumentation that is important in events during low power operation and shutdown. Under such conditions, certain systems may require manual actuation, and possibly additional instrumentation to provide the necessary cues/information to operators. Please provide an expanded assessment that includes consideration of instrumentation needs during low power operation and shutdown.

Response:

The PAM Technical Specification is applicable in Modes 1, 2, and 3, which ranges from hot full power in Mode 1, down to a keff < 0.99 and an RCS Tavg > 350°F in Mode 3, to provide the indications necessary to mitigate DBAs occurring in these modes. Section 4.1 of WCAP-15981 discusses the operator actions that are assumed in the DBA analysis that are cued from PAM instrumentation. The evaluation of the DBAs considers the Modes of Applicability, i.e., Modes 1 through 3 of the PAM Technical Specification, which includes low power operation. The DBA analyses performed at hot full power bound those analyses at low power, with a few exceptions, such as, the main steam line break at hot zero power core response. Section 4.3 of WCAP-15981 discusses the instrumentation utilized in the EOPs, which are entered following a reactor trip or safety injection. The DBA analysis, EOPs, at-power PRA, SAMG, and EPIP are sufficient to determine the appropriate PAM instrumentation that should be included in the PAM Technical Specification for these Modes. The at-power PRA analyses also bound the PRA analyses at low power.

The PAM Technical Specification is not applicable in the shutdown and refueling Modes (4, 5 and 6), therefore a shutdown PRA is not required to determine the PAM instrumentation required in those Modes.

The third bullet, "Risk Impact," on page 10 of WCAP-15981 was be revised to delete the text "... as well as insights from mode transition (startup and shutdown transition)."

(A revision to page 10 is provided in Attachment 2.)

8. The methodology assumes that all EOP operator actions that are important for preventing core damage are modeled in the plant PRA. The converse would also appear to be true, i.e., any instrument identified in the topical report as important to risk would relate to an important operator action in the EOPs (or in the SAMG). This would imply that any instrument identified in Table 7 as significant to risk should also be identified (in Table 7) as significant to EOPs (or SAMG). This concept has not been consistently applied in Table 7. For example, pressurizer level and RWST level instruments are both indicated to be significant to risk, but neither instrument is indicated to be significant to EOPs or SAMG. A similar relationship may also exist between EOPs and EALs, i.e., an instrument identified in the topical report as important to an EAL might also relate to an important operator action in the EOPs or SAMG. Please provide a more consistent accounting of the significance of the various instrumentation to the EOPs, considering the relationship between the EOP operator actions and the PRA and EALs.

Response:

As stated in Section 4.3 of WCAP-15981, all of the important EOP actions would be identified as important PRA actions or important for the declaration of Emergency Action Levels in the EPIPs. It should also noted that all of the operator actions assumed in the DBA analyses for which no automatic actuations are available should also be associated with important EOP actions.

Table 7 of WCAP-15981 was revised to properly reflect this relationship. Section 4.3 of WCAP-15981 was also revised to reflect the relationship between the DBA assessment and the EOPs.

(The revisions to Section 4.3 and Table 7 are provided in Attachment 2.)

9. Although a high instrument importance in the PRA might constitute a basis for including an instrument in technical specifications, a low importance in the PRA would not necessarily constitute a basis for removing an instrument from technical specifications. Several aspects of the PRA model would need to be critically assessed at a plant-specific level before using a

PRA to support such a relaxation. These include the resolution of all relevant PRA quality issues, the relationship between the instrument and the associated human actions, the completeness of the human reliability and systems models in areas related to the instrument/operator actions, and the quantification of these models. Each of these aspects of the PRA would need to be assessed on a plant-specific basis, rather than generically, based on the Westinghouse PRA database/survey. Accordingly, the topical report should be modified to include a clear statement of the plant-specific assessments and reviews of the PRA that each utility would be expected to perform if instrumentation is to be relocated from the technical specifications on the basis of risk significance.

Response:

The plant specific PAM instrumentation to be included in the plant specific PAM Technical Specification will be determined utilizing the plant specific PRA which meets certain requirements for technical adequacy to ensure that the operator actions are adequately considered in the PRA model. Specifically, the licensee's PRA should be based on a PRA whose scope and technical adequacy meets the current industry requirements for risk informed applications.

WCAP-15981 Sections 3.1, 7, and 8 were revised to clarify that the plant specific PRA, which meets certain technical adequacy requirements, will be utilized to determine the plant specific instrumentation that will be included in the plant specific PAM Technical Specifications.

(The revisions to Sections 3.1, 7, and 8 are provided in Attachment 2.)

10. Justify why RCS Subcooling Margin should not be included within the PAM technical specification, given that the topical report found this instrument to be important in DBAs, PRAs, EOPs, and EALs, and that the parameter is also required for ERDS.

Response:

RCS subcooling was found to be an important parameter for diagnosing challenges to core cooling and for ensuring that adequate margins for core cooling were maintained while taking actions to mitigate the consequences of accidents. As discussed on page 38 of WCAP-15981, the RCS Subcooling Monitor indication is derived from a correlation using the core exit temperature and RCS pressure. While the RCS Subcooling Monitor is typically the primary indication relied upon by the plant operating staff in the EOPs, the operators are trained to independently validate the RCS Subcooling Monitor indication from the RCS temperature (via the core exit thermocouples) and RCS pressure indications. Since both the core exit temperature and RCS pressure indications are already considered to be important instruments and are proposed to be included in the PAM Technical Specification, the operators have a highly reliable and available means of determining RCS subcooling. Since a means of determining RCS subcooling is available using the instrumentation included in the proposed PAM Technical Specification, it is not necessary to include the indication provided by the RCS subcooling instrumentation in the PAM Technical Specification.

Additionally, see the responses to General Comment RAI Number 4 and Specific Information Request RAI Number 1 regarding ERDS.

11. The discussion in Section 8 states that plant-specific implementation of the topical report methodology only requires a confirmation of the generic evaluations contained in the report. For the PRA portion of the assessment, the only guidance provided is that the utility should ensure that the PRA Peer Review findings (for the internal events) have been addressed. In the NRC staff's view, a more comprehensive evaluation would be needed at the plant-specific level if instrumentation is to be relocated on the basis of risk significance. To determine whether additional instrumentation should be included in technical specifications, the evaluation would include: (1) generation and evaluation of plant-specific importance listings (the generic assessment described in the topical report may be incomplete since the 2002 survey did not include "RAW" importances, and since important human actions from the latest plant-specific PRA may not have been captured in the Westinghouse PRA database), (2) identification of instrumentation associated with any additional important operator actions, and (3) confirmation that the instrumentation needed to support risk important operator actions has been appropriately considered. To determine if specific instrumentation can be relocated to licensee controlled documents, the evaluation would include an assessment of: (1) the relationship between the instrument and the associated human actions, (2) the completeness of the human reliability and systems models in areas related to the instrument/operator actions, and (3) the adequacy of the quantification of these models. The utility evaluation would also include consideration of the plant-specific risk analyses for external events and low power/shutdown. The discussion on methodology implementation needs to better describe the plant-specific risk assessments that are expected to be performed by the utility, and the manner in which the results of these assessments are to be used in the implementation process.

Response:

Sections 3.2, 7, and 8 were revised to clarify that a plant specific assessment of the DBA analyses, PRA, EOPs, SAMG and EPIPs, using the methodology described in this report is required, to determine the plant specific PAM Technical Specification instrumentation. Thus, the quantitative and qualitative assessments in this report only serve to demonstrate the generic methodology to be used in a plant specific evaluation.

Sections 3.1 and 8 were revised, as discussed in the response to Specific Information Request RAI Number 9 above, to include requirements on PRA technical adequacy for assessing the instrumentation to be included in the PAM Technical Specification.

Section 8 was revised to identify the details of a plant specific PAM instrumentation evaluation by adding a flowchart that illustrates the process that a licensee would use to determine whether a specific instrument should be included in the PAM Technical Specification or relocated to a licensee controlled document.

As discussed in the response to RAI Number 7, the PAM Technical Specification is not applicable in Modes 4, 5 and 6. Therefore, insights from shutdown or transition PRA assessments do not need to be considered in the evaluation of the PAM instrumentation.

(The revisions to Sections 3.1, 3.2, 7 and 8 are provided in Attachment 2.)

12. Please provide a flowchart or logic diagram depicting the process that a utility would be expected to follow to determine whether a specific instrument should be included in the PAM technical specification or licensee controlled documents. Important considerations within the process should include: (1) how the instrument relates to Criterion 3 and 4 of 10 CFR 50.36 (c)(2)(ii), (2) whether the instrument supports important operator actions in the plant-specific internal events PRA, external events risk assessment, and shutdown risk assessment, (3) whether the instrument is important for other purposes, such as EOPs, EALs, etc. (if this is in fact a consideration in the decision), (4) how the instrument would be classified using the RG 1.97 classification approach (if this is in fact a consideration in the decision), and (5) whether alternate indications are available in lieu of the specific instrument (if this is in fact a consideration in the decision). The flowchart should also depict the process that a utility would be expected to follow to: (1) confirm that the plant-specific risk models (for internal events, external events, and shutdown events) are of suitable quality for this application (i.e., peer review findings that could impact the identification and ranking of important operator actions and associated instrumentation have been resolved), (2) confirm that the plant-specific risk models are of sufficient detail to reflect the risk significance of the specific operator actions and instruments, and (3) document the results of the risk evaluation.

Response (Overall):

A flowchart that illustrates the process that a licensee would use to determine whether a specific instrument should be included in the PAM Technical Specification or relocated to a licensee controlled document was provided in the revised Section 8.

Response to 12 (1):

See the response to General Comment Number 2 regarding how it is determined whether the PAM instrumentation satisfies to Criteria 3 and 4 of 10 CFR 50.36 (c)(2)(ii).

Response to 12 (2):

See the discussion on pages A-7 through A-11 of WCAP-15981 regarding the instrumentation that supports important operator actions in the internal events PRA.

See the discussion in the second paragraph on page 56 and pages A-13 and A-14 of WCAP-15981 regarding external events.

See the response to Specific Information Request RAI Number 7 above regarding a shutdown risk assessment.

Response to 12 (3):

See the response to General Comment RAI Number 4 regarding the use of instrumentation in the EOPs, PRA, SAMG, and EPIP. See the discussion on pages 21 through 23 of WCAP-15981 regarding the use of EALs to determine what PAM instrumentation should be included in the PAM Technical Specification.

Response to 12 (4):

There is no Regulatory Guide 1.97 classification that is used as input to determine whether the PAM instrumentation should be included in the PAM Technical Specification. The assessment described in this report is an independent assessment of instrumentation importances based on current accident management understanding and knowledge. After the assessment with respect to Criteria 3 and 4 of 10 CFR 50.36 is complete, the Regulatory Guide 1.97 classification should be updated for consistency with the assessment performed. Those instruments that satisfy Criterion 3 of 10 CFR 50.36 would then be classified as a Regulatory Guide 1.97 Type A variable. Similarly, those instruments that satisfy Criterion 4 of 10 CFR 50.36 would then be classified as a Regulatory Guide 1.97 Category I variable.

Response to 12 (5):

The alternate indications that were identified for the PAM instrumentation proposed to be included in the PAM Technical Specification are discussed in Table 13 on page 49 of WCAP-15981. The identification of alternate indications does not input into the determination of whether PAM instrumentation should be included in the PAM Technical Specification. The alternate indications were identified to allow unit operation to continue beyond 30 days with one inoperable PAM channel or beyond 7 days with two inoperable PAM channels, in lieu of a unit shutdown for those PAM functions that were determined to have alternate indications. This provision is allowed by Required Action B.1 for one inoperable PAM channel, and Required Action F.1 for two inoperable Reactor Vessel Water Level or Containment Area Radiation (High Range) channels in Technical Specification 3.3.3, "PAM Instrumentation," in NUREG-1431.

(The revisions to Section 8 are provided in Attachment 2.)

ELECTRICAL AND INSTRUMENTATION AND CONTROLS BRANCH RAIs
(Received May 16, 2005 via an e-mail from G. Shukla (NRC) to S. DiTommaso (W))

1. Regulatory Guide (RG) 1.97 grouped the variables to be monitored during and after an accident into five types. RG 1.97 recommends that Category 1 instrumentation provide the operator with information on the key variables for (1) plant specific Type A variables, (2) the accomplishment of four Type B plant safety functions (reactivity control, core cooling, reactor coolant system (RCS) integrity, and containment integrity), (3) the potential for breach or actual breach of three Type C fission product barriers (fuel cladding, reactor coolant pressure boundary, and containment), (4) the operation of three Type D safety systems and other systems important to safety (primary containment system, secondary system, and auxiliary feedwater system), and (5) the magnitude of release of radioactive materials of one Type E variable (containment radiation). These functions, potential for breach, system status, and magnitude are referred to as functions in this request for additional information.

   WCAP-15981 examines each variable that is in the NUREG-1431 (STS) post accident monitoring (PAM) technical specifications (TSs) or in plant specific PAM TSs and determines the highest function that each variable served, but does not examine each RG 1.97 function and how the RG 1.97 variables serve each function. The WCAP appears to not consider that some variables serve multiple functions and multiple types and therefore might also fall into multiple categories.

   The format of the WCAP should be revised to address each RG 1.97 function under each type, address the key variables for each function, and appropriately categorize each key variable. If RG 1.97 designated a variable as a key variable for a particular function, but the WCAP analysis suggests it should not be a key variable, the WCAP should identify the key variables for that function with appropriate justification. Additionally, the WCAP should provide the new categorization of any proposed downgrade of variables, along with appropriate justification as it relates to each function.

Response:

Technical Specification 3.3.3, "PAM Instrumentation," in NUREG-1431, "Standard Technical Specifications Westinghouse Plants," contains a Reviewer's Note that states: "Table 3.3.3-1 shall be amended for each unit as necessary to list: 1) All Regulatory Guide 1.97, Type A instruments and 2) All Regulatory Guide 1.97, Category 1, non-Type A instruments in accordance with the unit's Regulatory Guide 1.97, Safety Evaluation Report."

As discussed on pages 3 and 4 of WCAP-15981, WCAP-15981 was prepared to evaluate the non-Type A, Category 1 instrumentation to determine whether it should be included in the PAM Technical Specification based on the staff's conclusion in a 1988 NRC letter which states: "the staff is unable to confirm the Owners Groups' conclusion that Category 1 Post-Accident Monitoring Instrumentation is not of prime importance in limiting risk (Criterion 4)."

The PAM instrumentation was evaluated in WCAP-15981 with respect to the Criteria of 10 CFR 50.36 (specifically Criteria 3 and 4), which are the only Criteria applicable to the PAM instrumentation Technical Specification. The EOPs were utilized in the methodology contained in WCAP-15981 to determine the instrumentation that is used to perform specific manual actions assumed in the DBA analyses for which there is no automatic actuation of equipment provided. The instrumentation utilized in the EOPs to perform specific manual actions that are assumed in the DBA analyses satisfy Criterion 3 of 10 CFR 50.36, and should be included in the PAM Technical Specification.

The PAM instrumentation was also evaluated in WCAP-15981 from a risk perspective based on risk insights obtained from the PRA in terms of the important operator actions identified based on risk importance, instrumentation utilized in key SAMG operator actions, and in key operator actions from the EPIP. If the PAM instrumentation was shown to be important to risk mitigation in the PRA, SAMG, or EPIP, it satisfies Criterion 4 of 10 CFR 50.36 and should be included in the PAM Technical Specification.

The reclassification of the instrumentation was performed to reflect how the instrumentation is currently utilized in accident management, as opposed to the classification identified when the original plant specific Regulatory Guide 1.97 evaluations were performed. The evaluation of the current instrumentation utilized in accident management is consistent with the reclassification of the containment hydrogen monitors based on their use in accident management as discussed in the 10 CFR 50.44 rulemaking. Therefore a complete reclassification of the PAM instrumentation that identifies all of the functions and types is not necessary to evaluate the PAM instrumentation to determine whether it satisfies Criteria 3 and/or 4 of 10 CFR 50.36. The only changes to the Regulatory Guide 1.97 classifications that are necessary are for the instrumentation whose assessment with respect to Criteria 3 and 4 of 10 CFR 50.36 differs from that in the original Regulatory Guide 1.97 classification. It should be noted that no instrumentation upgrade due to the reclassification to Regulatory Guide 1.97 Type A or Category I is required to include this instrumentation in the PAM Technical Specification.

2. The WCAP recommends that RCS pressure, core exit temperature, pressurizer level, steam generator level (wide range), and steam generator pressure be reclassified as Type A. However, since Type A variables are plant specific, it is not clear how the WCAP justifies the recommendation that a variable be a generic Type A. Please explain the concept of generic Type A variables and how it would be applied on a plant specific basis.

Response:

The instrumentation that should be included in the PAM Technical Specification based on 10 CFR 50.36 Criterion 3 were determined based on a generic evaluation of the DBA analyses as discussed in Section 4.1 of WCAP-15981 and a review of the WOG Emergency Response Guidelines (ERGs) as discussed in Section 4.3 of WCAP-15981. The evaluation that identified that the instrumentation satisfies Criterion 3 of 10 CFR 50.36 would also need to reflect that that the instrumentation should be classified as a Regulatory Guide 1.97 Type A variable for consistency. Therefore, any instrumentation that satisfies 10 CFR 50.36

Criterion 3 should also be identified as a Regulatory Guide 1.97 Type A variable. The plant specific evaluation to determine which instrumentation satisfies Criteria 3 and/or 4 of 10 CFR 50.36 and the Regulatory Guide 1.97 classifications will be performed on a plant specific basis based on a review of the plant specific DBA analyses and EOPs as part of the plant specific implementation of WCAP-15981.

WCAP-15981 Sections 7 and 8 were revised to clarify that the plant specific DBA analyses and EOPs will be utilized to determine the plant specific PAM instrumentation to be included in the plant specific Technical Specifications.

(The revisions to Sections 7 and 8 are provided in Attachment 2.)

3. Some of the variables that the WCAP recommends for inclusion in the Technical Specifications (refueling water storage tank (RWST) level, high head safety injection (SI) flow, and steam generator pressure) are not currently classified as Category 1 in RG 1.97. Therefore, at some plants these instruments might not meet the redundancy, environmental qualification, seismic qualification, and power source criteria of Category 1 instrumentation. Is the WCAP proposing that licensees be forced to upgrade this instrumentation or request a deviation?

   If this instrumentation is not upgraded but is included in the Technical Specifications, changes in the number of channels or the listing of alternate channels of instrumentation must be written into plant specific Technical Specifications, which would deviate from the STS philosophy. Please discuss these topics.

Response:

NUREG-1431 currently requires that Regulatory Guide, 1.97, Type A instruments and Category I, non-Type A instruments be included in the PAM Technical Specification. Prior to the implementation of NUREG-1431, plant specific PAM Technical Specifications included/include Regulatory Guide 1.97, non-Category 1, non-Type A instruments and even some non-Regulatory Guide 1.97 instruments. The current PAM Technical Specifications for plants who have not converted to NUREG-1431 may also contain Regulatory Guide 1.97, non-Category 1, non-Type A instruments, as well as non-Regulatory Guide 1.97 instruments. The Technical Specification Actions address instrument inoperability for those Regulatory Guide 1.97, non-Category I, non-Type A instruments, non-Regulatory Guide 1.97 instruments, as well as the Regulatory Guide 1.97 Type A and non-Type A, Category I instruments.

Including these Regulatory Guide 1.97 instruments (refueling water storage tank (RWST) level, High Head safety injection (SI) flow, and steam generator pressure) in the PAM Technical Specification if they are not classified as Regulatory Guide 1.97, Category I instruments is acceptable, since the PAM Technical Specification Actions will address instrument inoperability for all of the PAM Instrumentation, including any non-Category I PAM Instrumentation.

The Bases for current Action (A.1) in Technical Specification 3.3.3, "PAM Instrumentation," of NUREG-1431 discusses PAM functions that only have one required channel and other non-Regulatory Guide 1.97 instrumentation available to monitor the function as a basis for the 30 day Completion Time. Additionally, the current Actions in Technical Specification 3.3.3 of NUREG-1431 allow unit operation to continue beyond 30 days with one PAM channel inoperable (Required Action B.1), and beyond 7 days with two PAM channels inoperable for the Reactor Vessel Water Level and Containment Area Radiation (High Range) functions (Required Action F.1) based on having alternate indications. The Bases for Required Action F.1 in Technical Specification 3.3.3 of NUREG-1431 discuss that alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation may be temporarily installed, and that unit operation may continue beyond 30 days with both PAM channels inoperable for these two functions. Specification 5.6.7, "Post Accident Monitoring Report," in NUREG-1431 discusses the use of pre-planned alternate methods of monitoring inoperable PAM instrumentation (Conditions B and F).

WCAP-15981 does not require an upgrade in classification, or a deviation to the Regulatory Guide 1.97 classification if any of these instruments are Regulatory Guide 1.97, non Category I, non-Type A instruments, since the Technical Specifications will address instrument inoperability.

4. For the reactivity control function the WCAP appears to disagree with the RG 1.97 statement: "If two or more instruments are needed to cover a particular range, overlapping of instrument span should be provided." RG 1.97 recommends Category 1 neutron flux instrumentation with a range of 10-6% to 100% full power for the reactivity control function. However the WCAP recommends that source range neutron flux, which monitors 10-6% to 1%, should be a backup variable because it provides diagnostics for maintaining subcriticality during RCS cooldown and depressurization. Isn't it important for the operator to determine that the reactor is actually shutdown?

   How would the operator verify that the reactor is actually shutdown without information from the source range neutron flux instrumentation?

Response:

For all accident sequences, immediate subcriticality would be achieved without operator actions by the insertion of control rods into the core, which is part of the plant design basis for all DBAs except the large break LOCA. For the large break LOCA, the blowdown forces may result in an inability to insert control rods, and the rapid injection of large quantities of highly borated water from the accumulators and RWST ensures that subcriticality is achieved with no operator actions. Failure to achieve initial subcriticality by control rod insertion would be diagnosed by the plant operators using the power range neutron flux indication as prescribed by the plant EOPs. As discussed in Sections 4 and 5 of WCAP-15981, the generic assessment has determined that the power range neutron flux indication can be an important PAM instrument that satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii). Additionally, the power range neutron flux indication does not satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii), since automatic features ensure that initial subcriticality is achieved.

In the longer term, the potential for recriticality is only a concern during RCS depressurization to cold shutdown conditions for accident sequences where significant borated water has not been injected into the RCS. In this case, the EOPs instruct the operators to determine the required RCS shutdown boron concentration and then borate the RCS to the required level before proceeding with the RCS cooldown and depressurization. Thus, the optimal recovery guidelines in the EOPs do not rely on the source range monitor. The source range monitor is only used in the Functional Restoration Guideline portion of the EOPs for the diagnosis of a potential loss of core shutdown margin. The analyses and evaluations that support the PRA model typically show that this action is screened out of the PRA model based on the low probability for accident sequences in which recriticality could occur in a success path. Therefore, the source range neutron flux indication does not satisfy Criterion 4 of 10 CFR 50.36 (c)(2)(ii). Additionally, the source range neutron flux indication does not satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii), since automatic features ensure that initial subcriticality is achieved.

Therefore the source range neutron flux indication is not included in the generic list of instruments in the proposed PAM Technical Specification in NUREG-1431.

5. For the core cooling function the WCAP appears to disagree with the RG 1.97 statement: "The measurement of a single key variable may not be sufficient to indicate the accomplishment of a given safety function. Where multiple variables are needed to indicate the accomplishment of a given safety function, it is essential that they each be considered key variables and measured with high-quality instrumentation." RG 1.97 recommends Category 1 instrumentation for RCS hot leg temperature, RCS cold leg temperature, RCS pressure, and reactor vessel water level to monitor the core cooling function. However the WCAP recommends that RCS hot leg temperature, RCS cold leg temperature, and reactor vessel water level should be backup variables because they provide either backup core cooling information or diagnostic core cooling information and that core exit temperature as monitored by the core exit thermocouples, as monitored by the core exit thermocouples (CETs), should be used as the key variable for the core cooling function. The WCAP does not mention RCS pressure in the core cooling function discussion. The core cooling function discussion should discuss all of these variables.

   How would the operator verify that core cooling is taking place based on core exit temperature alone?

   How would the operator determine that the core is covered or uncovered without knowing the reactor vessel water level?

   The WCAP says of RCS subcooling, "The inputs to the RCS subcooling monitor are the CETs for RCS temperature and the wide range RCS pressure indication for RCS pressure." However, a number of plants use information from the CETs, RCS hot leg temperature, RCS cold leg temperature, and RCS pressure as inputs to RCS subcooling. Since RCS hot leg temperature and RCS cold leg temperature are input to RCS subcooling, shouldn't they be considered primary information and, therefore, be classified as Category 1?

Contrary to the WCAP assessment, RCS hot leg temperature and RCS cold leg temperature are currently classified as Type A at approximately 41 Westinghouse units. Please explain this contradiction.

Response:

Section 5.1 of WCAP-15981 discusses the evaluation of the Core Exit Temperature, RCS hot leg temperature, RCS cold leg temperature, and reactor vessel water level instrumentation with respect to whether it should be included in the PAM Technical Specification, by determining whether they satisfy Criterion 3 and/or Criterion 4 of 10 CFR 50.36. Only the Core Exit Temperature and RCS Pressure indications are proposed to be included in the PAM Technical Specification based on satisfying Criterion 4 of 10 CFR 50.36. This assessment concluded that only the core exit thermocouples can provide a direct indication of core cooling. Hot leg and cold leg RTD indications can be affected by accident conditions that may mask the actual core cooling condition (e.g., the impact of SG reflux cooling in the hot leg RTDs). Therefore, the RCS hot leg temperature, RCS cold leg temperature, and reactor vessel water level instrumentation are proposed to be relocated from the PAM Technical Specification to a licensee controlled document since they do not satisfy Criterion 3 or 4 of 10 CFR 50.36. Not all of the instrumentation utilized in the EOPs is included in the PAM Technical Specification.

The most direct inputs to determining RCS subcooling are the core exit thermocouples (CETs) for RCS Temperature, and wide range RCS Pressure indications. Both of these indications are proposed to be included in the PAM Technical Specification by WCAP-15981. Even if the actual plant RCS Subcooling Monitor uses the RCS hot leg or cold leg temperature inputs for determining RCS subcooling, the core exit thermocouples are an adequate alternate and preferred indication for this determination. The core exit thermocouples provide the highest indication of the RCS fluid temperature since they are located at the core outlet region of the reactor vessel, and therefore provide a minimum subcooling indication.

RCS hot leg temperature and RCS cold leg temperature are currently classified as a Regulatory Guide 1.97 Type A indication based on the current Regulatory Guide 1.97 evaluations of PAM Instrumentation that may not have determined how this instrumentation is utilized in the DBA analyses and EOPs. If it is determined that this instrumentation is a Regulatory Guide 1.97 Type A indication based on the plant specific DBA analyses and EOPs, then this instrumentation would be included in the PAM Technical Specification for that plant.

6. For the RCS integrity and reactor coolant pressure boundary functions the WCAP appears to disagree with the RG 1.97 statement: "The measurement of a single key variable may not be sufficient to indicate the accomplishment of a given safety function. Where multiple variables are needed to indicate the accomplishment of a given safety function, it is essential that they each be considered key variables and measured with high-quality instrumentation." RG 1.97 recommends Category 1 RCS pressure, containment sump water level (wide range),

and containment pressure instrumentation to monitor the RCS integrity function. RG 1.97 also recommends Category 1 RCS pressure, containment pressure, and containment sump water level (wide range) instrumentation to monitor the reactor coolant pressure boundary function. However, the WCAP recommends that containment sump water level (wide range) should provide information on the status of SI from the RWST and should, therefore, be Category 2. The WCAP should discuss the role of containment sump water level (wide range) instrument in the RCS integrity and reactor coolant pressure boundary functions.

How would the operator determine the amount of water in containment to support switchover to recirculation without knowing the containment sump water level?

How would the operator determine if a break in RCS piping is inside or outside containment without containment sump water level?

How is the WCAP recommendation for RWST level being included in the TSs affected based on automatic switchover to recirculation, semiautomatic switchover to recirculation, or manual switchover to recirculation?

Contrary to the WCAP assessment, containment sump water level (wide range) is currently classified as Type A at approximately 18 Westinghouse units. Please explain this contradiction.

Response:

The diagnosis of RCS pressure boundary integrity as a critical safety function in the EOP functional restoration guidelines does not rely on the containment water level indication. A loss or potential loss of RCS integrity is diagnosed in the EOPs from RCS pressure, RCS temperature (for pressurized thermal shock concerns only) and pressurizer level. All of these parameters are indicated by instrumentation that has been determined to satisfy Criterion 3 or 4 of 10 CFR 50.36 for other reasons (e.g., RCS pressure wide range, core exit temperature and pressurizer level) and proposed to be included in the PAM Technical Specification. Therefore, the PAM instrumentation provides a means for the diagnosis of a loss, or potential loss, of RCS pressure boundary integrity. However, since the automatic actuation of systems and components in response to a loss of RCS integrity is included in the design of Westinghouse PWRs, pressurizer level and RCS pressure are not important for diagnosing a loss of the RCS pressure boundary. Similarly, RCS pressure and RCS temperature are used in the EOPs as indicators of a potential loss of RCS integrity due to pressurized thermal shock concerns. However, the potential for a loss of RCS integrity due to pressurized thermal shock is not a DBA, and has been shown to be a negligible PRA contributor to risk (Reference: Technical Basis for Revision of the Pressurized Thermal Shock (PTS) Screening Criteria in the PTS Rule (10CFR50.61), Draft, December 2002, Accession Number ML030090632). Therefore, containment sump level wide range is not used as an indicator of RCS pressure boundary integrity.

The use of the containment sump level wide range indication in accident management is discussed on page 37 in Section 5.1 of WCAP-15981.

As discussed on page 38 of Section 5.1, the RWST level alarms and/or indication are utilized to obtain information regarding the switchover to the emergency core cooling and containment spray recirculation mode.

For the diagnosis of a LOCA inside containment, the containment sump water level is used in the EOPs, as the third indication (after the containment pressure and containment radiation indications). Following a reactor trip and automatic initiation of safety injection (based on low pressurizer pressure) any one of the three indications is sufficient for the operators to diagnose a LOCA condition; the other two indications may provide confirmation of the LOCA. For example, in the case of a small LOCA (e.g., less than 2 inch equivalent diameter) that results in an SI signal, the first indication would likely be a small increase in containment radiation levels and potentially a slight increase in containment pressure (e.g., less than 1 psig). Depending on the break location, the break water might not quickly reach the containment sump and provide an indication of a containment sump level increase. Additionally, for the diagnosis of a LOCA outside containment, following reactor trip and automatic initiation of safety injection the containment sump water level indication (e.g., no increase in containment sump level) is the third indication utilized in the EOPs (after a decreasing RCS pressure indication and an increasing auxiliary building radiation indication). For the most probable LOCA outside containment, according to PRA studies, is the interfacing system LOCA outside containment in the low pressure RHR piping connected to the RCS. This would likely result in a containment sump water level indication, since the flow from the relief valves on the RHR piping is routed back to pressurizer quench tank whose rupture disk would quickly open and release fluid to the containment. Thus "no containment sump level" is not a reliable indicator of a LOCA outside containment. In summary, the diagnosis of RCS pressure boundary integrity as a critical safety function in the EOP functional restoration guidelines does not rely on the containment sump water level indication.

Depending on the plant design, some plant designs provide automatic switchover to the recirculation mode, while other designs provide semi-automatic switchover to the recirculation mode, and some designs require manual switchover. The automatic or semi-automatic switchover function is provided by the Engineered Safety Features Actuation System (ESFAS) function based on RWST level, and is included in the ESFAS Instrumentation Technical Specification for those plant designs. Some of the automatic switchover to the recirculation mode designs also require an RWST Low-Low Level signal coincident with a Containment Sump Level- High signal to prevent spurious switchover. The RWST Low-Low Level signal coincident with a Containment Sump Level-High Function is included in the ESFAS Instrumentation Technical Specification for those plant designs. If the switchover to the recirculation mode is provided manually, it is first cued from the RWST alarm and not the RWST level indication, nor the Containment Sump Water Level (Wide Range) indication. If the switchover to the recirculation mode is provided manually utilizing the RWST Level indication, the RWST level indication would be included in the PAM Technical Specification as proposed by WCAP-15981, and identified as satisfying Criterion 3 of 10 CFR 50.36 and identified as a Regulatory Guide 1.97, Type A variable. Table 10 was revised to reflect that the RWST Level is a Regulatory Guide 1.97, Type A variable for those plants that utilize its indication for manual or semi-automatic switchover to the recirculation mode.

WCAP-15981 evaluated the Containment Sump Water Level (Wide Range) instrumentation with respect to whether it should be included in the PAM Technical Specification by determining whether it satisfies Criterion 3 and/or Criterion 4 of 10 CFR 50.36.

The Containment Sump Water Level (Wide Range) instrumentation is proposed to be relocated from the PAM Technical Specification to a licensee controlled document since it does not satisfy Criterion 3 or 4 of 10 CFR 50.36, however, it will still be available for monitoring purposes. Not all of the instrumentation utilized in the EOPs is included in the PAM Technical Specification.

Containment sump water wide range is currently classified as a Regulatory Guide 1.97 Type A variable based on the current Regulatory Guide 1.97 evaluations of PAM Instrumentation that may not have determined how this instrumentation is utilized in the DBA analyses and EOPs. If it is determined that this instrumentation is a Regulatory Guide 1.97 Type A indication based on the plant specific DBA analyses and EOPs, then this instrumentation would be included in the PAM Technical Specification for that plant.

WCAP-15981 Sections 4.1, 5.1 and Table 10 were revised to be consistent with the information provided in this response.

(The revisions to Sections 4.1, 5.1 and Table 10 are provided in Attachment 2.)

7. For the operating status of the auxiliary feedwater (AFW) system, the WCAP appears to disagree with the RG 1.97 statement: "The measurement of a single key variable may not be sufficient to indicate the accomplishment of a given safety function. Where multiple variables are needed to indicate the accomplishment of a given safety function, it is essential that they each be considered key variables and measured with high-quality instrumentation." RG 1.97 recommends Category 1 condensate storage tank level instrumentation to monitor the operating status of the AFW system. However, the WCAP has recommended that condensate storage tank level should be downgraded to Category 2 and should provide information to indicate whether a continued steam generator heat sink can be maintained and long term AFW system operating status.

   It appears that the WCAP justifies using AFW flow in lieu of condensate storage tank level as the key variable for the AFW system status. Please explain the relationship between these variables with respect to AFW system status.

   How would the operator verify that there is sufficient water to feed the AFW system without knowing the condensate storage tank level?

   Contrary to the WCAP assessment, condensate storage tank level is currently classified as Type A at approximately 16 Westinghouse units. Please explain this contradiction.

Response:

As discussed in Section 5.1 of WCAP-15981, the AFW Flow and Steam Generator Level instrumentation provide the indications used in the EOPs for diagnosing issues related to the performance of the AFW system. The primary diagnosis used in the EOPs for inadequate AFW performance is the AFW flow rate indication. The second symptom used in the EOPs to diagnose inadequate AFW performance is a decreasing SG water level. CST level is not used in the diagnosis of inadequate AFW performance.

While the CST level instrumentation is the primary indication of the ability to continue to provide AFW flow to the steam generators to provide a secondary side heat sink for decay heat removal from the reactor core, CST refill is a long-term action that is typically not required in the first 16 to 20 hours after an accident. For the DBA events, the plant would either be on normal RHR cooling (for non-LOCA events) or ECC recirculation in a time frame well before the CST inventory is exhausted. Operator actions to refill the CST based on low CST level indication are modeled in some PRA models. The results of the PRA assessment in Appendix A of WCAP-15981 show that the CST level indication has a low risk significance. The low risk significance is based on: a) the low probability that natural circulation would be the only means of maintaining the core in a safe stable state following an accident, and b) the long time to deplete the CST during which CST refill would have begun and been monitored based on the available CST level indications (including local indications) if long term natural circulation decay heat removal was selected as the long term safe stable state.

WCAP-15981 evaluated the condensate storage tank level instrumentation with respect to whether it should be included in the PAM Technical Specification by determining whether it satisfies Criterion 3 and/or Criterion 4 of 10 CFR 50.36. Since it does not satisfy Criterion 3 or 4 of 10 CFR 50.36, the condensate storage tank level instrumentation is proposed to be relocated from the PAM Technical Specification to a licensee controlled document. If it is determined that the condensate storage tank level indication is risk important form a plant specific PRA, then this instrumentation should be included in the PAM Technical Specification for that plant.

The condensate storage tank level is currently classified as a Regulatory Guide 1.97 Type A indication based on the current Regulatory Guide 1.97 evaluations of PAM Instrumentation that may not have determined how this instrumentation is utilized in the DBA analyses and EOPs. If it is determined that this instrumentation is a Regulatory Guide 1.97 Type A indication based on the plant specific DBA analyses and EOPs, then this instrumentation would be included in the PAM Technical Specification for that plant.

WCAP-15981 Section 5.1 was revised to be consistent with the information provided in this response.

(The revisions to Section 5.1 are provided in Attachment 2.)

8. The WCAP includes a discussion of alternate instrumentation for power range neutron flux, high head SI flow, containment area radiation (high range), steam generator water level (wide range), and auxiliary feedwater flow. Some of these alternate instruments either are not currently classified as Category 1, the WCAP recommends for downgrade from Category 1, or are not part of the RG 1.97 program. To take credit in the Technical Specifications for alternate instrumentation, the alternate instrumentation should also be in the Technical Specifications. Please revise the discussion of alternate instrumentation to include only Category 1 instruments that are included in the Technical Specifications.

Response:

Technical Specification 3.3.3, "PAM Instrumentation," in NUREG-1431 allows the use of Regulatory Guide 1.97 non-Category I instrumentation as alternate instrumentation for inoperable PAM instrumentation and the alternate instrumentation does not have to be included in the Technical Specifications as discussed below.

The Bases for current Action (A.1) in Technical Specification 3.3.3, "PAM Instrumentation," of NUREG-1431 discusses PAM Functions that only have one required channel and other non-Regulatory Guide 1.97 instrumentation available to monitor the function as a basis for the 30 day Completion Time. Additionally, the current Actions in Technical Specification 3.3.3 of NUREG-1431 allow unit operation to continue beyond 30 days with one PAM channel inoperable (Required Action B.1), and beyond 7 days with two PAM channels inoperable for the Reactor Vessel Water Level and Containment Area Radiation functions (Required Action F.1) based on having alternate indications. The Bases for Required Action F.1 in Technical Specification 3.3.3 of NUREG-1431 discuss that alternate means of monitoring Reactor Vessel Water Level and Containment Area Radiation (High Range) may be temporarily installed, and that unit operation may continue beyond 30 days with both PAM channels inoperable for these two functions. Specification 5.6.7, "Post Accident Monitoring Report," in NUREG-1431 discusses the use of pre-planned alternate methods of monitoring inoperable PAM instrumentation (Conditions B and F).

The justification for the use of alternate instrumentation contained in Section 6 of WCAP-15981 was revised to provide a more complete discussion of the adequacy of the instrumentation proposed to be used as alternate instrumentation for the PAM instrumentation included in the PAM Technical Specification.

(The revisions to Section 6 are provided in Attachment 2.)

TECHNICAL SPECIFICATION SECTION RAIs
(Received May 26, 2005 via an e-mail from G. Shukla (NRC) to S. DiTommaso (W))

1. "The STS (NUREG-1431) Post Accident Monitoring Instrumentation, Table 3.3.3-1 requires all Regulatory Guide 1.97, Type A instruments and all Regulatory Guide 1.97, Category 1, non-Type A instruments in accordance with the unit's Regulatory Guide 1.97, Safety Evaluation Report. WCAP-15981 proposes changes that will revise the list to include generic Type A instruments and revise the categorization of certain Category 1 instruments. Provide a markup of STS LCO 3.3.3 and the LCO 3.3.3 Bases to show the proposed changes to the staff precedent in the STS."

Response:

The Technical Specification and Bases markups that reflect the changes to Technical Specification 3.3.3 of NUREG-1431 that are proposed by WCAP-15981 will be provided by April 14, 2006.

Attachment 2

Changes to WCAP-15981

Key for Changes:

PSB-GC:	Plant Systems Branch - General Comments RAIs
PSB-SIR:	Plant Systems Branch - Specific Information Requests RAIs
EICB:	Electrical and Instrumentation and Controls Branch RAIs
TSB:	Technical Specification Branch RAIs
Telecon:	Changes discussed with NRC Staff on April 25 and June 20, 2005.
Underlined Text	New text added.
Balloon Text;	Deleted text.

LIST OF FIGURES

LIST OF ACRONYMS

AC	Alternating Current
AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
AOP	Abnormal Operating Procedure
ATWS	Anticipated Transient Without Scram
BAT	Boric Acid Tank
CA	Computational Aid (in SAMG)
CCW	Component Cooling Water
CDA	Core Damage Assessment
CDF	Core Damage Frequency
CET	Core Exit Thermocouples
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
DBA	Design Basis Accidents
DC	Direct Current
E-Plan	Emergency Plan
EAL	Emergency Action Level
ECC	Emergency Core Cooling
ECCS	Emergency Core Cooling System
EFW	Emergency Feedwater (equivalent to AFW)
EOP	Emergency Operating Procedures
EPIP	Emergency Plan Implementing Procedures
ERG	Emergency Response Guidelines
ESFAS	Engineered Safety Feature Actuation System
FRG	Functional Restoration Guidelines
F-V	Fussell-Vesely
HPME	High Pressure Melt Ejection
HRA	Human Reliability Analysis
IPE	Individual Plant Examination
LCD	Licensee Controlled Document
LCO	Limiting Conditions for Operation
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
NEI	Nuclear Energy Institute
NSSS	Nuclear Steam Supply System
ODCM	Offsite Dose Calculation Manual
NR	Narrow Range
NRC	Nuclear Regulatory Commission
PAM	Post Accident Monitoring
PASS	Post Accident Sampling System
PORV	Power Operated Relief Valve (refers to pressurizer)
PRA	Probabilistic Risk Assessment
PWR	Pressurized Water Reactor

Instrumentation is not of prime importance in limiting risk (Criterion 4). Recent PRAs have shown the risk significance of operator recovery actions which would require a knowledge of Category 1 variables. Furthermore, recent severe accident studies have shown significant potential for risk reduction from accident management. The Owners Groups' should develop further risk-based justification in support of relocating any or all Category 1 variables from the Standard Technical Specifications." The Owners Groups participating in the development of the NUREG-1431 choose not to evaluate the inclusion of Regulatory Guide 1.97 Non Type A, Category 1 instrumentation in the PAM Technical Specification at that time. Therefore, Technical Specification 3.3.3 was issued with the requirement that all plant specific Regulatory Guide 1.97 Type A, and all plant specific Regulatory Guide 1.97 Category 1 instrumentation be included in the PAM Technical Specification.

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This report was developed to specifically address the NRC request to further evaluate the inclusion of Regulatory Guide 1.97 Category 1 variables in the PAM Technical Specification. In addition, this report provides a generic methodology for developing a technical basis for relocating certain Post Accident Monitoring instruments from the Technical Specifications. The conclusions contained in this report are based on generic risk insights (i.e., evaluations against 10 CFR 50.36 (c)(2)(ii) Criterion 4) and a re-evaluation of the overall basis for Accident Monitoring instrumentation with respect to the first three Criteria of 10 CFR 50.36 (c)(2)(ii). This report also includes the consideration of the reliance on the instrumentation not specifically evaluated when the list of PAM instrumentation was originally developed in NUREG-1431. These additional considerations include instrumentation required to mitigate the consequences of beyond design basis accidents, such as those that are important for Severe Accident Management (e.g., SAMG), and offsite emergency radiological protection actions (e.g., Emergency Action Level (EAL) declarations and offsite dose calculations).

The purpose of the PAM instrumentation is to provide a reliable means of monitoring plant variables and systems following an accident (Reference 2). These indications of plant variables are required by the operators during accident situations to (Reference 2):

- Permit the operator to take pre-planned manual actions to accomplish safe plant shutdown,
- Determine whether systems important to safety are performing their intended functions, and
- Enable the determination of the potential for a gross breach of the barriers to radioactivity release.

In addition, there are other indications of plant variables that provide information on the operation of systems important to safety to the operators during an accident to:

- Permit operators to make appropriate decisions on the use of systems, and

- Permit the early determination of the need to initiation offsite emergency radiological protective actions and estimate the magnitude of the threat.

The indications of plant variables important to safety, according to the above criteria, are classified in Regulatory Guide 1.97 according to the definitions in Table 1.

Table 3 PAM Instrumentation Contained in NUREG-1431	
Power Range Neutron Flux	Penetration Flow Path Containment Isolation Valve Position
Source Range Neutron Flux	Containment Area Radiation (High Range)
Reactor Coolant System Hot Leg Temperature	Pressurizer Level
Reactor Coolant System Cold Leg Temperature	Steam Generator Water Level (Wide Range)
Reactor Coolant System Pressure (Wide Range)	Condensate Storage Tank Level
Reactor Vessel Water Level	Core Exit Temperature (Quadrants 1-4)
Containment Sump Water Level (Wide Range)	Auxiliary Feedwater Flow
Containment Pressure (Wide Range)	

Some instrumentation not contained in Technical Specification 3.3.3 of NUREG-1431, is contained in the PAM Technical Specifications of other Westinghouse NSSS plants. In most cases, these plants have not converted to NUREG-1431. The additional PAM instrumentation included in the Technical Specifications for these plants are identified in Table 4.

Table 4 PAM Instrumentation Not Contained in NUREG-1431	
Auxiliary Feedwater (AFW) Valve Position	RCS Subcooling Margin
Boric Acid Tank (BAT) Level	Residual Heat Removal (RHR) Flow
Condenser Air Ejector (High Range)	Refueling Water Storage Tank (RWST) Level
Containment Enclosure Negative Pressure	Pressurizer Safety Valve Position
Containment Sump Water Level (Narrow Range)	Spray Additive Tank (SAT) Level
Containment Pressure (Narrow Range)	Spent Fuel Pool Exhaust Radiation (High Range)
Containment Water Level (Wide Range)	Steam Generator Blowdown Radiation
Intermediate Range Neutron Flux	Steam Generator Pressure
Plant Vent Stack (High Range)	Steam Generator Water Level (Narrow Range)
Pressurizer Pressure	Steam Line Radiation
Power Operated Relief Valve (PORV) Position	Turbine Driven Auxiliary Feedwater (TDAFW) Pump Exhaust Radiation
PORV Block Valve Position	High Head Safety Injection Flow

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Since the results from the licensee's PRA will be one of several inputs used to identify the plant specific instrumentation that satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii), the acceptable PRA scope and technical adequacy required to support this application must be considered. PRA technical adequacy is addressed through the PRA peer reviews and self assessments using a variety of guidance, including the American Society of Mechanical Engineers (ASME) PRA Standard (Reference 7), Nuclear Energy Institute (NEI) PRA Peer Review Process Guidance (Reference 8) and/or Regulatory Guide 1.200 (Reference 9). The purpose of these references is to assure that the PRA is of sufficient technical robustness to be used in regulatory applications. As stated in Section 2.2.3 of Regulatory Guide 1.174 Revision 1:

> *"The scope, level of detail, and technical acceptability of the PRA are to be commensurate with the application for which it is intended and the role the PRA results play in the integrated decision process. The more emphasis that is put on the risk insights and on PRA results in the decision making process, the more requirements that have to be placed on the PRA, in terms of both scope and how well the risk and the change in risk is assessed.*
>
> *"Conversely, emphasis on the PRA scope, level of detail, and technical acceptability can be reduced if a proposed change to the LB results in a risk decrease or is very small, or if the decision could be based mostly on traditional engineering arguments, or if compensating measures are proposed such that it can be convincingly argued that the change is very small."*

The identification of the instrumentation that satisfies Criterion 3 or 4 of 10 CFR 50.36 (c)(2)(ii) that should be included in the PAM Technical Specification is based on the operator importances from the DBA analyses, the PRA and severe accident management and emergency plan actions from the SAMG and EPIP. As shown in Table 7 for the generic results, most of the instrumentation that were found to satisfy Criterion 3 or 4 of 10CFR50.36(c)(2)(ii) for inclusion in the PAM Technical Specification are based on several of the inputs and not solely the PRA results. In addition, the PRA is only used as a risk ranking tool (e.g., use of relative risk importances rather than delta-CDF and delta-LERF). Therefore, the technical adequacy of the PRA does not need to be at the highest levels for this application.

The important features of the PRA that can impact its use in the identification of the instrumentation that satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii) are the completeness and technical adequacy of the operator actions to prevent core damage or mitigate the consequences of LERF sequences. The role of instrumentation in risk is found through the importance of operator actions modeled in the PRA that are cued from instrumentation. Therefore, it is important to assure that the operator actions that could prevent core damage or mitigate LERF are included in the PRA model and are appropriately modeled. The risk importance of instrumentation will have the greatest sensitivity to this aspect of the PRA. Of secondary importance are the technical adequacy and completeness of the accident sequence identification and quantification and the technical adequacy of the data used in the PRA for initiating event frequencies and equipment reliability.

The more extensive PRA technical adequacy requirements contained in References 7 and 9, while assuring a more robust PRA, are not required for this application, since the determination of the PAM Technical Specification instrumentation does not rely solely on the PRA and the CDF and LERF values determined from the PRA model.

The PRA scope necessary to assure that important risk insights are included in the determination of the PAM instrumentation should include at least an at-power PRA for internal initiating events that considers

CDF (a Level 1 PRA), as well as early fission product releases (a LERF assessment) and at least a qualitative assessment of late containment failures, and core damage risks from seismic, fire and shutdown initiating events. The qualitative assessment of external events and shutdown risks will generally result in a more conservative approach in determining the safety significance of components, compared to a quantitative PRA assessment. A review of the important operator actions from several Westinghouse NSSS plants with a fully quantified external events PRA, as discussed in Appendix A, has shown that the important operator actions that are based on control room instrumentation in the external events PRA are the same as those already determined to be significant from the internal events PRA.

3.2 METHODOLOGY

The overall methodology used for assessing the importance of instrumentation to be included in the PAM Technical Specification is similar to the methodology (Reference 10) developed and used in the successful elimination of Post Accident Sampling System (PASS) requirements that specifically addressed offsite emergency radiological protection aspects important to safety.

Although the approach used in this report uses the results of PRA assessments, it is not a risk-informed application in accordance with Regulatory Guide 1.174. Rather than focusing on the five elements of a risk informed approach as specified in Regulatory Guide 1.174, this approach directly assesses the importance of instrumentation with respect to the Criteria of 10 CFR 50.36 (c)(2)(ii). This direct assessment uses the plant DBA analyses, PRA, EOPs, SAMG and EPIP as the basis for assigning importance to the instrumentation. Therefore, the methodology used in this report is more prescriptive than a risk informed approach.

PAM instrumentation is intended to provide indications of plant parameters that are the basis for important operator actions to bring the plant to a safe stable state in the event of an accident. The information available to make this determination includes:

- Design Basis Accidents – While most DBAs rely on instrumentation that provides a signal to automatically initiate systems and components to bring the plant to a safe stable state, there are also several key operator actions assumed in the DBA analyses.
- Probabilistic Risk Assessment – The PRA models a number of operator actions to bring the plant to a safe stable state and prevent core damage.
- Emergency Operating Procedures – The EOPs provide guidance for the operator response to an accident, based on instrumentation indications of plant parameters. The EOPs are the basis for the PRA and DBA operator action modeling.

Deleted: The NRC Staff Requirements (Reference 6) regarding the acceptable PRA scope and quality to support regulatory applications has also been considered in developing the recommendation for the appropriate PAM instrumentation. Phase 1 of Reference 6 allows the use of Regulatory Guides 1.174 and 1.177 to be used. PRA quality is addressed through the PRA peer reviews, the American Society of Mechanical Engineers (ASME) PRA Standard (Reference 7), Nuclear Energy Institute (NEI) PRA Peer Review Process Guidance (Reference 8) and the draft Regulatory Guide 1.200 (Reference 9). The purpose of these efforts is to assure that the PRA is of sufficient quality to be used in regulatory applications. The PRA scope necessary to assure that important risk insights are included in the determination of the PAM instrumentation should include at least an at-power PRA for internal initiating events that considers CDF (a Level 1 PRA), as well as early and late fission product releases (a Level 2 PRA) and at least a qualitative assessment of seismic, fire and shutdown risks. The qualitative assessment of external events and shutdown risks will generally result in a more conservative approach to determining the safety significance of components, compared to a quantitative PRA assessment. A review of the important operator actions from several Westinghouse NSSS plants with a fully quantified external events PRA has shown that the important operator actions that are based on control room instrumentation in the external events PRA are the same as those already determined to be significant from the internal events PRA. Therefore, licensees using the methodology in this report need to provide evidence that their PRA meets the NRC Staff Requirements for Phase 1 of Reference 6. That is, the licensee's PRA should be based on the PRA scope and quality for Westinghouse NSS ... [1]

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- Severe Accident Management Guidance – The SAMG provides guidance for the operator response to mitigate the consequences of a severe core damage, including protecting fission product boundaries. The SAMG operator actions are based on instrumentation indications of key plant parameters.

- Emergency Plan and Emergency Plan Implementing Procedures – The EPIPs provide guidance for making decisions regarding offsite radiological prctective actions based on the indications of plant parameters for several key instruments.

The following screening criteria have been developed for assessing the importance to safety of the PAM instrumentation, as described below and summarized in Table 5.

Table 5 Screening Criteria for Assessing PAM Instrumentation

Area	Criteria
Design Basis Accidents	Is credit taken for operator actions in the DBA analyses documented in the Updated Final Safety Analysis Report (UFSAR) based on instrumentation indications? Instrumentation that supports these operator actions satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).
Probabilistic Risk Assessment	Is credit taken for operator actions in the PRA for a high risk significant function based on instrumentation indications? A high risk significance is defined from CDF and LERF Risk Achievement and Risk Reduction metrics. Instrumentation that supports these operator actions satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).
Emergency Operating Procedures	No screening criteria; importance of EOP measures is included in the DBA and PRA assessments.
Severe Accident Management Guidance	Does the instrumentation provide an indication that would result in operator actions to prevent failure of a fission product barrier that could produce a "large early release" or a "large late release"? Instrumentation that supports these operator actions satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).
Emergency Plan Implementing Procedures	Does the instrumentation provide a risk significant indication used to classify an accident according to the appropriate EAL? Only those criteria that would result in the declaration of a General Emergency condition are considered risk significant. Instrumentation that supports these operator actions satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).
	Does the instrumentation provide a primary indication used to assess the severity of potential fission product releases according to the Offsite Dose Calculation Manual (ODCM)? Instrumentation that supports these operator actions satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).
	Does the instrumentation provide a primary indication of the degree of core damage for the Core Damage Assessment (CDA) from which offsite radiological protection actions might be taken? Instrumentation that supports these operator actions satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

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Screening criteria have not been developed for determining the instrumentation that are utilized in the EOPs. The EOPs identify a wide range of instrumentation that are the basis for operator actions. While some of the instrumentation may be important in the DBA and PRA accident analyses, a larger portion of the instrumentation is used to verify plant conditions and the success of EOP prescribed actions and is therefore not of high safety significance. Further, the operator actions in the DBA and PRA analyses are based on the instrumentation specified in the EOPs. Therefore, the screening criteria for the DBA and PRA will identify the importance of the instrumentation utilized in the EOPs.

Although this is not a risk-informed application, some of the basic elements of Regulatory Guide 1.174 have been addressed in this application. In particular, this report provides:

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- Reason for Proposed Change – The reason for change touches on each of the identified categories: the change improves operational safety by including certain key risk significant instruments in the Technical Specifications that were not previously included; the change enhances the consistency of risk basis in regulatory requirements by providing a sound technical basis for satisfying Criterion 4 of 50.36 (c)(2)(ii); and the change reduces unnecessary regulatory burdens by removing certain instruments form the PAM Technical Specifications that do not directly impact safety.

- Defense in Depth – Defense in Depth has been considered to ensure that a reasonable balance among prevention of core damage, prevention of containment failure, and consequence mitigation is preserved by maintaining those instruments in the PAM Technical Specification that are important for preventing core damage, maintaining containment integrity and implementing offsite emergency planning activities. Also, redundancy, independence, and diversity are maintained by identifying those instruments that can be used as back-ups to the instruments included in the PAM Technical Specifications.

- Safety Margins – Safety margins are maintained by ensuring that the instrumentation used to support operator actions credited in the design basis accident analyses are controlled by the PAM Technical Specifications.

- Risk Impact – The risk impact of instrumentation to support operator actions is considered by using the available risk assessment tools, as discussed in Appendix A, including the at-power PRA, the fire and seismic PRA assessments, the Level 2 PRA containment integrity assessment, the Severe Accident Management Guidance and the Site Emergency Plan. Risk importance measures were used to identify instrumentation that supports risk significant operator actions in the Level 1 PRA. The assessments from the other risk assessment tools (e.g., Level 2 PRA, SAMG, E-Plan) were more qualitative, but provide the key insights regarding the importance of instrumentation in preventing or mitigating risk significant conditions.

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- Instrumentation that is relocated from the PAM Technical Specifications to LCDs will still be monitored for availability and subject to appropriate corrective action where appropriate.

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Therefore, it is concluded that an appropriate process has been used to consider the re-definition of the plant instrumentation that should be included in the PAM Technical Specification and a re-classification of the PAM instrumentation proposed to be relocated from the Technical Specifications, similar to the re-classification of the hydrogen monitors from Category 1 to Category 3 in the 50.44 rulemaking.

The methodology for determining the PAM instrumentation that should be included in the Technical Specifications, and the PAM instrumentation that can be relocated from the Technical Specifications was based on generic DBA, PRA, EOP, SAMG, and EPIP information for Westinghouse NSSS plants. Therefore, implementation of this methodology on a plant specific basis requires the confirmation of the generic conclusions contained in the WCAP by reviewing the plant-specific DBA analyses, PRA, EOP, SAMG, and EPIP.

4 INSTRUMENTATION ASSESSMENT

This section provides the results of an assessment of the use and importance of instrumentation in the DBA analyses, the PRA, the EOPs, the SAMG, and the E-Plan/EPIPs.

4.1 DESIGN BASIS ACCIDENT ANALYSIS

While many of the DBAs are analyzed assuming the automatic actuation of systems and components, several of the DBAs also assume operator actions. The operator actions modeled in the DBA analyses are based on conservative time windows available for action, but are based on reliable instrumentation indications to diagnose the need for such actions. The DBAs that typically assume operator actions in the safety analyses are discussed below. The instrumentation indications upon which the operator actions are based would therefore satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

Loss of Coolant Accidents

In the event of a Loss of Coolant Accident (LOCA), the design basis analyses assume that the operator takes the appropriate actions for the transfer to Emergency Core Cooling (ECC) recirculation based on RWST level. In some older plant designs, the transfer to ECC recirculation consists entirely of manual actions by the operators, whereas in the newer plant designs, most or all of the required actions are automatic. There are no other short term operator actions assumed in the design basis LOCA analyses. In all cases, the operators would be alerted to the RWST inventory decrease to a point where transfer to the recirculation mode is required by a control room alarm and/or by the initiation of those automatic actions associated with switchover to ECC recirculation. The RWST level would typically only be used to confirm the initiation of the transfer to recirculation, based on either automatic actions or a switchover alarm. In some older plant designs, RWST level alone, without alarm indication, is the basis for cueing the operator initiation of switchover to ECC recirculation.

At a specified time after the initiation of the accident (e.g., 4 to 20 hours depending on plant specific analyses), the design basis analysis assumes that a switchover to hot leg recirculation is required to limit the potential for boron build-up in the reactor vessel. This is performed manually by the operators. However, the cue to perform hot leg recirculation switchover is based on time as opposed to any plant variables.

Additionally, the radiological dose analysis for the LOCA is typically based on continued operation of containment spray after the RWST has been emptied. For many large dry containment plants in the WOG fleet, an assumed operator action to transfer containment spray to the recirculation mode when the RWST is nearly empty (based on a low-low level alarm) is embedded in the design basis analyses. Failure to transfer containment spray pump suction from the injection mode to the recirculation mode could result in damage to the containment spray pumps. For plant designs that use the containment spray pumps for spray recirculation, the failure to switch to containment spray recirculation could impact the containment pressure response assumed in the design basis analyses. Thus, the RWST level indication could be an important indication for a DBA in which no automatic control is provided.

accident condition and the need for operator actions. A portion of the operator error assessment is based on the availability and accuracy of the instrumentation indication that is the basis for the operator action. Operator actions that are important for accident prevention and accident mitigation are modeled in the PRA. Therefore, if a parameter indication (i.e. instrument) does not support an operator action modeled in the PRA, then it can be assumed to be of very low risk significance. The methodology for the treatment of instrumentation in the operator error assessment varies from plant to plant, but is typically included in the model in an explicit manner.

Key PRA results obtained from a survey of all Westinghouse NSSS plants are available in a composite PRA database. The importance of operator actions for preventing core damage for at-power initiating events identified in the PRA database have been analyzed in detail to determine the importance of instrumentation required for those operator actions. A detailed discussion of this analysis is presented in Appendix A of this report. A detailed assessment of the importance of operator actions to prevent failure of containment fission product boundaries (e.g., LERF and late containment failures) has also been completed and is included in Appendix A of this report.

From a risk perspective, the following indications have been determined to typically have a high degree of importance for preventing core damage for at-power initiating events, according to a composite PRA model of Westinghouse NSSS plants:

- RWST Level (median RAW = 10.35),
- SG Wide or Narrow Range Level* (median RAW = 4.05)
- RCS Subcooling (median RAW = 4.05),
- RCS Temperature (median RAW = 4.05),
- RCS Pressure (median RAW = 4.05),
- Pressurizer Level (median RAW = 4.05),
- SG Pressure (median RAW = 4.05),
- High Head SI Flow (Median RAW = 3.05),
- Power Range Neutron Flux Monitor (RAW = 2.49),
- SG Wide Range Level** (median RAW = 2.46), and
- AFW Flow (Median RAW = 2.46).

*Based on maintaining SG level during RCS cooldown and depressurization

**Based on initiation of bleed and feed mode of core cooling

The following instrumentation has been detemined to typically have a high degree of importance for preventing large, early radioactive releases, based on the LERF assessment discussed in Appendix A.6. No importance measures have been quantified for the following instrumentation, as the LERF assessment was qualitative in nature:

- Containment Pressure (Wide Range),
- Penetration Flow Path Containment Isolation Valve Position, and
- RCS Pressure.

From a risk perspective, all other instrumentation has a low or negligible importance for preventing core damage, according to a composite PRA model of Westinghouse NSSS plants and therefore does not satisfy Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

4.3 INSTRUMENTATION UTILIZED IN EMERGENCY OPERATING PROCEDURES

The EOPs for Westinghouse NSSS plants are based on the generic WOG Emergency Response Guidelines (ERGs) (Reference 11). The ERGs were developed to provide procedures for bringing the plant to a safe stable state for any accident sequence initiated at power operation that results in a reactor trip or SI signal. The ERGs are designed to be consistent with the DBA analyses, but also consider accidents beyond the design basis. In addition, the ERGs provide guidance for the use of all means to bring a plant to a safe stable state. That is, in the event of a failure of a plant system or component assumed to be operable in the design basis analyses, the ERGs provide alternate methods for achieving the same desired endstate.

Considering all of the contingency procedures for dealing with events beyond the design basis, the ERGs make use of a large amount of the plant instrumentation in providing guidance to the operators for bringing the plant to a safe stable state. The plant PRA models the significant paths through the EOPs for a wide range of possible initiating events. The plant PRA model will typically model all of the EOP actions assumed in the DBA analyses. If the EOP action is not modeled in the PRA, then it is considered to have a negligible impact on plant risk. EOP actions might not be included in the PRA model for several key reasons:

- Failure to perform the EOP action does not impact the accident sequence progression and therefore does not impact the PRA results,
- The EOP action is on a pathway that has been shown to be of very low probability and therefore does not impact PRA results, or
- The EOP action is very late in the accident sequence such that the probability of failing to take the action is considered negligible. This rationale is seldom used but can apply when the time at which the action is required approaches 24 hours after the initiating event. Examples include switchover to hot leg recirculation and refilling the Condensate Storage Tank (CST), which are typically not required in the first 12 to 24 hours of the accident.

The EOPs include Functional Restoration Guidelines (FRGs). These are symptom-based indications that an accident is not proceeding according to the design basis. The FRGs are of particular relevance in this assessment since the FRGs also have links to EALs for implementation of offsite radiological protective actions as discussed Section 4.5.1. The response in the FRGs is classified according to the severity of the deviation of the symptom from an expected condition. The most severe classification is called a "red path," which signifies a significant deviation that requires an immediate response to attempt to bring the value of that parameter closer to the expected value. The FRG red paths, along with the instrumentation used to diagnose the red path, are:

- Subcriticality – Power Range Neutron Flux
- Core Cooling – Core Exit Thermocouples (CETs) (primary indication), Reactor Vessel Level and RCS Subcooling, which is indicated from CETs and RCS Wide Range Pressure (secondary indication)
- Heat Sink – SG Wide Range Level (primary indication), Total Feedwater Flow (secondary indication)
- Integrity – RCS Wide Range Pressure, RCS Cold Leg Resistance Temperature Detectors (RTDs)
- Containment – Containment Wide Range Pressure

All EOP operator actions that are important for preventing damage to the reactor core are modeled in the plant PRA. Additionally, EOP instrumentation that may be important for an offsite emergency response to protect the health and safety of the public is included in the EAL declaration criteria. Therefore, the importance of EOP instrumentation is deferred to the DBA, PRA and EAL discussions (Sections 4.5.1 and 4.5.2). Separate consideration of the impact of instrumentation in the EOPs is redundant to the assessment of the importance of instrumentation in the PRA and EALs, and is therefore not necessary.

The new core damage assessment methodology relies solely on instrumentation to determine the occurrence of and degree of core damage. The methodology uses two primary indicators, based on the analytical modeling of a wide range of core damage accidents:

- CETs, and
- Containment radiation

Due to the variability in these indications across a wide range of potential core damage sequences, a series of secondary indicators was specified. The variability in the indications from these secondary indicators across the same range of accident sequences is much larger than the variability of the primary indicators. However, it is believed that these secondary indicators could be used to confirm the primary indications. Where differences in the expected behavior between the primary and secondary indicators are found, a number of considerations are called upon to arrive at a best estimate of the occurrence of core damage and the degree of core damage. The secondary indicators used in WCAP-14696 are:

- Containment hydrogen,
- Reactor vessel level indication,
- RCS hot leg RTDs, and
- Source range neutron flux

It should be noted that the instrumentation for core damage assessment is also used in other key functions discussed in this report. None of the instrumentation recommendations in this report are solely based on the core damage assessment.

4.5.3 Offsite Dose Calculation Manual

The ODCM is an offsite emergency planning tool used to project offsite doses in the event of an accident. Typically, the ODCM initial input to the dose projections is the UFSAR dose analysis or the PRA Level 2 source term analyses. However, once information from the actual event becomes available, that current information can be used to refine the offsite dose projections.

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Typically, the plant information that is most useful in refining the offsite dose projections is the containment radiation levels as indicated by the containment radiation monitor. This information is used to make projections of offsite dose levels in the event of a failure of the containment integrity. The containment radiation levels, in conjunction with the containment pressure, can also be used to project offsite doses from containment leakage. However, most often the offsite dose measurements are used in place of containment leakage assumptions, since the containment design leakage rate represents a conservative offsite dose projection. Therefore, containment pressure is not important to the ODCM.

The offsite dose projection tools used at most plants also include the capability to use effluent radiation monitor information as input to the dose projections. However, this is typically only used to validate the offsite field survey information, since any radiation releases indicated by effluent monitors would be classified as an ongoing release and the primary input would be from offsite field radiation surveys. Additionally, it is likely that effluent monitors would quickly become saturated in the event of an accident involving any significant fuel damage. Thus, the effluent monitors may not be available to provide information for offsite radiological protection recommendations in the EPIPs.

Therefore, only the containment radiation monitor is useful in refining the offsite dose projections using the ODCM.

Some plants do not rely on plant instrumentation for offsite dose projections and utilize default values contained in the UFSAR for offsite dose projections. For these plants, the containment radiation monitor would not be used for refining offsite dose projections using the ODCM.

4.6 SUMMARY OF INSTRUMENTATION IMPORTANCE

A composite list of PAM instrumentation relied upon in the DBA analysis, the PRA, accident management (EOPs and SAMG), and offsite emergency protective actions was determined based on the assessments discussed above. Table 7 provides a summary of the instrumentation that is relied upon in each of these applications, without making any assessment of the importance of the instrumentation for each application. Each of the instruments identified in Tables 7 and 8 is further assessed as to its importance in accident management and mitigation to determine whether it satisfies Criterion 3 or 4 of 10 CFR 50.36. The importance of the instrumentation will be discussed in Section 5.0 of this report.

Table 7 Significance of PAM Instrumentation Contained in Current Technical Specifications

Instrument	Design Basis Accident	Risk (PRA)	Accident Management		Emergency Plan		
			EOPs	SAMG	EAL	CDA	ODCM
PAM Instrumentation contained in NUREG-1431							
Power Range Neutron Flux		✔	✔		✔		
Source Range Neutron Flux						✔	
RCS Hot Leg Temperature	✔		✔	✔	✔	✔	
RCS Cold Leg Temperature			✔		✔		
RCS Pressure (Wide Range)	✔	✔	✔	✔	✔		
Reactor Vessel Water Level			✔		✔	✔	
Containment Sump Water Level (Wide Range)				✔			
Containment Pressure (Wide Range)		✔	✔	✔	✔		
Containment Isolation Valve Position		✔	✔		✔		
Containment Area Radiation (High Range)			✔		✔	✔	✔
Pressurizer Level	✔	✔	✔		✔		
Steam Generator Water Level (Wide Range)	✔	✔	✔	✔	✔		
Condensate Storage Tank Level							
Core Exit Temperature (Quadrants 1-4)		✔	✔	✔	✔	✔	
Auxiliary Feedwater Flow		✔	✔		✔		

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Table 7 (cont.) Significance of PAM Instrumentation Contained in Current Technical Specifications							
	Design Basis Accident	Risk (PRA)	Accident Management		Emergency Plan		
Instrument			EOPs	SAMG	EAL	CDA	ODCM
PAM Instrumentation NOT contained in NUREG-1431							
AFW Valve Position							
BAT Level							
Condenser Air Ejector (High Range)							✔
Containment Enclosure Negative Pressure							
Containment Sump Level (Narrow Range)							
Containment Pressure (Narrow Range)							
Intermediate Range Neutron Flux							
Plant Vent Stack (High Range)							✔
PORV Block Valve Position							
PORV Position							
Pressurizer Pressure							
RCS Subcooling Margin	✔	✔	✔				
RWST Level	✔	✔	✔				
Pressurizer Safety Valve Position							
SAT Level							
Spent Fuel Pool Exhaust Radiation							✔
Steam Generator Blowdown Radiation							
Steam Generator Pressure	✔	✔	✔		✔		
Steam Generator Water Level (Narrow Range)	✔	✔	✔	✔	✔		
Steam Line Radiation							✔
TDAFW Pump Exhaust Radiation							✔

Deleted: Component Cooling Water Flow Rate ... [2]

Deleted: Containment Water Level (Wide Range) ... [3]

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Table 8 provides an alternate summary of the potential PAM indications. In this summary, the manner in which the instrumentation is used in the various accident management tools is identified.

Table 8 Summary of Important Indications for Accident Management

Indication/Purpose	DBA	EOP	SAMG	PRA	E-Plan
SG Level					
• Diagnose SGTR	✔	✔		✔	
• Maintain SG heat sink	✔	✔		✔	✔
• Prevent SG overfill	✔	✔		✔	
• Initiate Bleed and Feed		✔		✔	
• Scrub Fission Products for SGTR			✔		
SG Pressure					
• Diagnose secondary side break or stuck open relief valve	✔	✔		✔	
• Cooldown target for RCS depressurization SGTR	✔	✔		✔	
RCS Pressure					
• Cooldown target for RCS depressurization	✔	✔		✔	
• High Pressure Melt Ejection prevention			✔	✔	
• Maintain cooldown rate	✔	✔		✔	
• RCS Integrity					✔
RCS Subcooling					
• Maintain subcooling during RCS cooldown and depressurization	✔	✔		✔	
• SI Termination	✔	✔		✔	
Pressurizer Level					
• SI termination to prevent pressurizer overfill	✔	✔		✔	
Core Temperature					
• Diagnose inadequate core cooling		✔	✔	✔	✔
Neutron Flux					
• Diagnose subcriticality		✔		✔	✔
Containment Pressure					
• Diagnose inadequate containment cooling		✔	✔	✔	✔
Containment Radiation					
• Diagnose core damage					✔
Containment Isolation Valve Position					
• Diagnose unisolated containment				✔	✔

Table 8 (cont.)	Summary of Important Indications for Accident Management				
Indication/Purpose	**DBA**	**EOP**	**SAMG**	**PRA**	**E-Plan**
RWST Level					
• Diagnose RWST refill				✔	
High Head SI Flow					
• Diagnose manual SI				✔	
Auxiliary Feedwater Flow					
• Diagnose loss of heat sink				✔	
Service Water Flow Rate System Availability					
• Diagnose loss of Service Water				✔	
Component Cooling System Availability					
• Diagnose loss of component cooling				✔	

Deleted: <#>Auxiliary Feedwat ... [4]

5 INSTRUMENTATION IMPORTANCE

The importance of the PAM instrumentation to plant safety should bear a direct relationship to the criteria in 10 CFR 50.36 (c)(2)(ii) and the Regulatory Guide 1.97 classification of the instrumentation. The importance of the instrumentation that is used in plant safety assessments and tools (i.e., identified in Table 7 and Table 8) was further evaluated to determine whether it satisfies the 10 CFR 50.36 criteria and to determine the applicable Regulatory Guide 1.97 classification with respect to its inclusion in the Technical Specifications. As noted previously, the original classification in Regulatory Guide 1.97 was done based on information and knowledge available in the early 1980's. This assessment is based on the information and knowledge currently available and can therefore be used to revise the original bases for the Regulatory Guide 1.97 classifications.

The assessment described in this section of the report focuses on that instrumentation that is relied upon in plant safety analyses, accident management and offsite protective actions. That is, each of the instruments identified in Tables 7 and 8 is further assessed as to its importance in accident management and mitigation to determine whether it satisfies Criterion 3 or 4 of 10 CFR 50.36. No further assessment is required for any instrumentation that is not relied upon in the safety assessments in this report. However, a brief discussion is merited on several of the current PAM instrumentation that are not considered to be significant for plant safety and is included at the end of the discussion of the primary instrumentation included in the DBA analysis and accident management.

5.1 INSTRUMENTATION RELIED UPON TO MITIGATE ACCIDENTS

This section provides a discussion of the results of an evaluation of the importance of instrumentation relied upon to mitigate accidents. The evaluation uses the screening criteria defined in Section 3.2 of this report. The results of the evaluation are expressed in terms of whether any of the 10 CFR 50.36 (c)(2)(ii) criteria (Criterion 3 and/or 4) are met. The recommended Regulatory Guide 1.97 classification of the instrumentation for the purpose of determining whether it should be included in the Technical Specifications is also presented.

Power Range Neutron Flux

The power range neutron flux indication provides the most direct indication of reactor criticality. The power range neutron flux instrumentation provides this indication for events in which subcriticality is not initially achieved. The intermediate range and source range neutron flux instrumentation provide an indication of sustained subcriticality, such as during and following RCS depressurization.

The Westinghouse NSSS plant PRA survey contained in Appendix A shows that power range neutron flux is a key indication for accident management operator actions to initiate manual reactor trip to bring the reactor to a subcritical condition. Subsequent operator actions to assure that the reactor remains in subcritical state, such as during and following RCS depressurization, were not determined to be important for long term core cooling. Therefore, the intermediate range and source range indications are not identified as key instruments in this assessment. Additionally, EALs in the E-Plan typically utilize the power range neutron flux as an indication of a potential loss of a fission product barrier in the assessment of the declaration of a General Emergency level and the potential need for offsite radiological protection actions. Therefore, the power range neutron flux indication meets Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

The RCS cold leg temperature indication provides information to indicate whether the core heat removal safety function is being accomplished and is therefore a 1.97 Type B variable. The RCS cold leg temperature wide range indication is a diagnostic indication and is therefore a Category 3 variable.

RCS Pressure (Wide Range)

The RCS pressure indication is used for all accident sequences. There is no other indication that can be used to directly indicate RCS pressure over the range of pressure required for accident management. Operator actions for a cooldown target for RCS depressurization and for maintaining subcooling (a combination of RCS pressure and temperature) during RCS cooldown and depressurization and for SI termination are performed using the RCS pressure indication. RCS subcooling, which utilizes RCS wide range pressure is also used as a backup for diagnosis of an inadequate core cooling condition. Also, operator actions in the EOPs and SAMG, utilize the RCS pressure indication to diagnose the need to depressurize the RCS to minimize the potential for containment integrity challenges from a high pressure melt ejection and to mitigate SGTR fission product releases that bypass the containment.

The DBA analyses indicate that RCS cooldown and depressurization for a SGTR accident, to below the SG pressure in the ruptured SG to terminate break flow, and for SI termination to prevent pressurizer overfill, are operator actions for which no automatic control is provided. Therefore, RCS pressure wide range satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii). Additionally, the PRA shows that RCS depressurization to terminate break flow for an SGTR event and depressurization of the RCS after core damage to prevent a high pressure melt ejection (see Appendix A) that could challenge containment integrity are risk significant operator actions. Therefore, RCS pressure wide range also satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

The RCS pressure wide range indication is a Type A variable since it provides information for operator action for SGTR break flow termination for which no automatic control is provided. RCS pressure wide range is a Category 1 variable, since, together with SG pressure, provides information to verify that break flow through a ruptured SG tube is terminated, thereby satisfying the inventory safety function.

Reactor Vessel Water Level

The reactor vessel water level indication is used in the plant EOPS as an indication of inadequate core cooling and as an indication of the potential for void formation that can interfere with natural circulation cooling. Some reactor vessel water level instrumentation only measures upper head voiding, versus others that measure well into the core region and therefore it only serves as a backup indication of upper head voiding and an indication of potential core uncovery. Since neither of these indication functions provide an indication for operator actions for which no automatic control is provided and the indication is not important from a risk perspective, it does not satisfy either Criterion 3 or 4 of 10 CFR 50.36 (c)(2)(ii) and should not be included in the Technical Specifications.

The reactor vessel water level indication provides information to indicate whether the core cooling safety function is being accomplished and is therefore, a Type B variable. The reactor vessel water level indication is a backup to the CETs for identifying an inadequate core cooling condition and is therefore a Category 3 variable.

Containment Sump Water Level (Narrow Range)

The containment sump water level indication provides information to indicate whether sufficient water is available in the containment sump at the time ECC is transferred from the injection mode to the recirculation mode, and when the recirculation spray system is automatically started for subatmospheric containments. It also provides an indication of excessive containment sump water levels that could result in flooding of key equipment and instrumentation. ECC injection (from the RWST) is switched over to recirculation (from the sump) to provide long term ECC when the RWST is emptied. The required operator actions associated with switchover to recirculation are plant specific, with some plants having fully automatic switchover, some having semi-automatic switchover, and some having totally manual switchover. The switchover to recirculation is initiated based on RWST level. For all DBA and for all accidents analyzed in the PRA where the RCS inventory loss is inside containment, the design of the plant ensures that there will be adequate water in the containment sump to support switchover to recirculation. Therefore, no operator action is required in the design basis analyses based on containment sump level. Since the containment sump water level narrow range indication does not provide an indication for operator actions for which no automatic control is provided, it does not satisfy Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

Containment water level instrumentation is used in the EOPs to define the loss of ECC recirculation capability. For diagnosis of a LOCA inside containment, the containment sump water level is used in the EOPs as the third indication (after the containment pressure and containment radiation indications). Additionally, for diagnosis of a LOCA outside containment, the containment sump water level indication is the third indication utilized in the EOPs (after a decreasing RCS pressure indication, and increasing auxiliary building radiation indication). The most probable LOCA outside containment, according to PRA studies, is the interfacing system LOCA outside containment in the low pressure RHR piping connected to the RCS. This would likely result in a containment sump water level indication, since the flow from the relief valves on the RHR piping is routed back to the pressurizer quench tank whose rupture disk would quickly open and release fluid to the containment. Thus "no containment sump level" is not a reliable indicator of a LOCA outside containment. In summary, diagnosis of RCS pressure boundary integrity as a critical safety function in the EOP functional restoration guidelines does not rely on containment water level indication. It is used in the SAMG to assure that adequate water is available in the containment sump(s) for ECC recirculation, should that capability to inject into the RCS from the containment sump become available.

In the PRA models, operator actions to refill the RWST based on inadequate containment sump level for continued core cooling are typically modeled for SGTR and LOCAs outside of containment. The risk importance of RWST refill identified in Appendix A shows that it can have a high risk importance for some plants, although the median value might not indicate a high risk importance. As PRAs are updated to more closely model the expected accident management strategies (as opposed to more conservative models), the RWST refill for these events may become more risk important. However, containment sump level would not be used as the primary indication for the need to begin RWST refill. There are a number of other indications available to provide information that RWST refill would be required for long term core cooling for these accidents. The accident type alone (e.g., SGTR or LOCA outside containment) and the current RWST level would be sufficient to provide an indication that long term core cooling using recirculation is not an available accident management strategy.

Although RWST refill may be risk important, containment sump water level is not the primary indicator of the need for operator action to begin RWST refill. Therefore, it is concluded that the containment sump water level narrow range indication does not provide an indication for operator actions which are important to mitigating core damage or containment releases and therefore it does not satisfy Criterion 4 of 10 CFR 50.36 (c)(2)(ii). Since containment sump water level narrow range does not satisfy either Criterion 3 or 4 of 10 CFR 50. 36(c)(2)(ii), it should not be included in the Technical Specifications.

The containment sump water level indication provides information to indicate whether the core cooling safety function can be accomplished when the Emergency Core Cooling System switchover to the recirculation mode of operation occurs, and is therefore a Type B variable. The containment sump water level narrow range indication provides information on the status of SI from the RWST and is therefore a Category 2 variable.

The pressurizer level indication provides primary information needed to permit the operators to take specified manual actions to terminate SI and is therefore a Type A variable. It also provides information related to satisfying the RCS inventory safety function to permit SI termination and is therefore a Category 1 variable.

Steam Generator Level (Wide Range)

SG level indication can be provided by either the narrow range or the wide range SG level instrumentation. Operator actions for diagnosis of a SGTR, maintenance of adequate SG level to provide a heat sink, controlling SG level to prevent SG overfill, and covering the tubes to scrub fission products for an SGTR are performed utilizing the SG narrow range level indication. However, the wide range SG indication encompasses the narrow range span and can be used in level ranges where the narrow range SG level indication is not available. The operators are trained in the use of wide range SG level indication, as well as the narrow range SG level indication. The initiation of bleed and feed can only be performed based on wide range SG level indication, since the narrow range SG level indication does not have sufficient range to enable the diagnosis of the need to initiate bleed and feed cooling, which is at a very low SG water level. Therefore, the SG level indication that can provide indication for all of the important operator actions is the wide range SG level instrumentation.

The design basis analyses assume that controlling SG level for long term core cooling and using SG level for the diagnosis of a SGTR are operator actions for which no automatic control is provided. Therefore, the SG wide range level indication satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii). The PRA shows that the initiation of bleed and feed core cooling, as well as the design basis functions, are risk significant operator actions. Also, the SAMG assessment shows that maintaining the water level over a ruptured SG tube is a risk significant operator action. Therefore, SG wide range level indication also satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

The SG wide range level indication provides information for operator action to maintain a heat sink following a DBA for which no automatic control is provided and is therefore a Type A variable. It also provides the direct verification of satisfying the heat sink safety function and is therefore a Category 1 variable.

Condensate Storage Tank Level

This instrumentation is used in the EOPs to define the potential loss of the SG heat sink due to low tank inventory as a continued water supply for the AFW system. Therefore, the CST level instrumentation is the primary indication of the ability to continue AFW flow to the steam generators to provide a secondary side heat sink for decay heat removal from the reactor core. CST refill is a long-term action that is not credited in the UFSAR analyses; CST refill is typically not required in the first 16 to 20 hours after an accident. For the design basis events, the plant would either be on normal RHR cooling (for non-LOCA events) or ECC recirculation in a time frame well before the CST inventory is exhausted. In the PRA models, operator actions to refill the CST based on low CST level indication are modeled in some PRAs. The results of the PRA assessment in Appendix A show that the CST level indication has a low risk significance. The low risk significance is based on: a) the low probability that natural circulation would be the only means of maintaining the core in a safe stable state following an accident, and b) the long time to deplete the CST during which CST refill would have begun and been monitored based on available CST level indications (including local indications), if long term natural circulation decay heat removal was selected as the long term safe stable state. Therefore, the CST level indication does not satisfy either Criterion 3 or 4 of 10 CFR 50.36 (c)(2)(ii) and should not be included in Technical Specifications.

Deleted: In the PRA models, operator action to refill the CST based on low CST level indication are modeled in some PRAs. The results of the PRA assessment in Appendix A show that the CST level indication has a low risk significance. Additionally,

The CST level control room indication provides information to indicate whether a continued SG heat sink can be maintained and is therefore a Type B variable. The CST level indication provides information for the long term AFW system operating status and is therefore a Category 2 variable.

indication of the need for further actions and the reliance on a decreasing SG water level may impact the probability of success of these operator actions. The AFW flow rate indication is the basis for a risk important operator action in the PRA and therefore satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

The AFW flow rate indication provides information used for the verification of the automatic actuation of AFW and is therefore a Type B variable. It provides the direct verification of satisfying the heat sink safety function and is therefore a Category 1 variable.

Containment Sump Water Level (Wide Range)

Containment Sump Water Level (Wide Range) and Containment Water Level are used interchangeably in this report. This instrumentation is used in the EOPs to define containment flooding. Although it is not used in the EOPs, the containment wide range water level could be used in the EOPs to verify that the contents of the RWST were emptied into the containment if the RWST level instrumentation were unavailable. The design basis containment water level is established to assure that no important components are submerged during a DBA. It is used in the SAMG to indicate the desired containment water level after core damage has occurred. In the SAMG, a backup method of containment water level is provided (Computational Aid, CA-4) based on the potential for the post core damage environment to render the containment water level instrumentation unavailable. The PRA does not model any operator actions related to containment water level using the wide range indications. Thus, it is concluded that the wide range containment water level instrumentation is not risk significant. Since there are no operator actions in the design basis analyses based on containment wide range water level, this indication does not satisfy Criterion 3 of 10 FR 50.36 (c)(2)(ii). The containment wide range water level indication does not support any risk important operator actions in the PRA and therefore this indication does not satisfy Criterion 4 of 10 FR 50.36 (c)(2)(ii).

The containment wide range water level indication provides information to indicate whether the core cooling safety function can be accomplished when the ECCS switchover to the recirculation mode of operation occurs, and is therefore a Type B variable. The containment wide range water level indication provides information on the status of SI from the RWST and is therefore a Category 2 variable.

Pressurizer Pressure

The pressurizer pressure is only specifically used in the EALs to determine the potential for loss of the RCS fission product barrier. It can be used elsewhere as a backup to the RCS pressure indication, but the range of the pressurizer pressure indication is very limited. Therefore, it is not typically used in the EOPs. This instrumentation is not considered to be risk significant. The pressurizer pressure indication does not support any risk important operator actions in the PRA and does not support any operator actions in the design basis analyses. Therefore this indication does not meet Criterion 3 or 4 of 10 CFR 50.36 (c)(2)(ii).

Because of its limited application, it is recommended that this instrumentation not be classified by the Regulatory Guide 1.97 definitions.

RCS Radiation Level

The RCS radiation level indication is typically provided by RCS letdown radiation monitors. These monitors are located in the letdown line, which is isolated upon the receipt of a SI signal. As discussed in WCAP-14986-A (Reference 16), the reactor coolant radiation level is only important for DBAs where there is fuel rod cladding damage without coincident core overheating, such as local reactivity events caused by the withdrawal of a single Rod Control Cluster Assembly (RCCA). For these events, the reactor is tripped and shutdown by the RPS. The letdown radiation monitor indication would be used by the plant operators to decide whether the declaration of an Unusual Event condition was appropriate. However, this determination is not shown to be important to risk in PRAs. Since the letdown radiation monitor indication does not provide an indication for operator actions for which no automatic control is provided and it is not important from a risk perspective, it does not satisfy either Criterion 3 or 4 of 10 CFR 50.36 (c)(2)(ii) and should not be included in Technical Specification.

The RCS radiation level indication provides information to indicate the potential for a breach of the fuel cladding fission product barrier and is therefore a Type C variable. The RCS radiation level indication provides diagnostic indications of core damage not associated with core overheating and is therefore a Category 3 variable.

RCS Subcooling Monitor

The RCS subcooling margin indication provides information to the operators related to satisfying one of the SI termination criteria following a steam line break or SGTR accident. The inputs to the RCS subcooling monitor are the CETs for RCS temperature and the wide range RCS pressure indication for RCS pressure. Since both of these indications are independently displayed in the control room and are also included in the Technical Specifications based on satisfying Criterion 3 and 4 of 10 CFR 50.36 (c)(2)(ii), the subcooling monitor provides a verification of the other indications. Therefore, it does not satisfy either Criterion 3 or 4 of 10 CFR 50.36 (c)(2)(ii) and should not be included in the Technical Specifications.

The RCS subcooling margin indication provides information to indicate whether the core cooling safety function is being accomplished, and is therefore considered a Type B variable. The RCS subcooling indication is a backup to the CETs and RCS pressure, and is therefore considered a Category 3 variable.

RWST Level (Wide Range)

This instrumentation is used in the design basis analyses to indicate the point at which transfer to ECC recirculation and containment spray recirculation should be initiated. The operator actions required for transfer to ECC and containment spray recirculation are typically cued based on the RWST low and low-low level alarms, as opposed to the RWST level instrumentation itself. RWST level instrumentation only validates the alarm and does not provide the primary indication for operator actions. The required operator actions associated with switchover to recirculation are plant specific, with some plants having fully automatic switchover, some having semi-automatic switchover, and some having totally manual switchover. Transfer to ECC recirculation was found to be a risk significant operator action in the PRA as discussed in Appendix A. While the PRA typically also models transfer to containment spray recirculation as an action to continue containment heat removal, risk importance measures are not available since they only potentially impact late containment failure probability and not core damage frequency. While the risk importance of transfer to containment spray recirculation would be greater for plants without safety related fan cooler units for containment heat removal, it does not impact the conclusions, since containment heat removal via containment spray also requires the ECC recirculation heat exchanger to be in operation. Since the operator action is taken based on the RWST low level and low-low level alarms, the RWST level instrumentation is not risk significant and is only used to validate the alarm function.

In addition, the RWST level instrumentation provides an indication of the need to initiate make-up to the RWST to maintain long term cooling. The PRA assessment in Appendix A shows that make-up to the RWST to provide long term core cooling for the SGTR and interfacing system LOCA accidents are risk significant operator actions that are keyed from the RWST level instrumentation. For all other accident sequences modeled in the PRA, refilling the RWST is typically not modeled in the PRA since it is only a remedial action; the RWST can only be refilled for a finite number of times and other actions also not modeled in the PRA would be required to achieve a safe stable state. Therefore, the RWST Level instrumentation satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

The RWST Level indication as used here refers to the wide range indication as opposed to the narrow range indication that is only used as a level indication associated with the Technical Specifications minimum required RWST level.

The RWST wide range level indication provides information to indicate the continued operation of SI for continued inventory control and is therefore a Type D variable. It also provides information to indicate the need to refill the RWST to continue inventory control for SGTR and ISLOCA events and is therefore a Category 1 variable.

Steam Generator Pressure

This instrument is used in design basis analyses and EOPs to indicate a loss of secondary side coolant accident (a main steamline or feedline break). It is also used in the design basis and EOP analyses for the SGTR accident to indicate the termination of the reactor coolant loss through the ruptured SG tube. Therefore, the SG pressure indication satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii). SG pressure is modeled in the PRA operator actions to terminate the break flow through a ruptured SG tube by depressurizing the RCS to a point just below the SG pressure, per the plant EOPs. Therefore, the SG pressure indication satisfies Criterion 4 of 10 CFR 50.36 (c)(2)(ii).

The SG pressure indication provides information for operator action for SGTR break flow termination for which no automatic control is provided and is therefore a Type A variable. Together with RCS pressure, the SG pressure indication provides information to verify that break flow through a ruptured SG tube is terminated thereby satisfying the inventory safety function and is therefore a Category 1 variable.

Steam Generator Narrow Range Level

This instrumentation is used in the design basis analyses and the EOPs to determine the SG level required for an effective heat sink, and as a primary means of diagnosing an event. It is used in the SAMG to indicate an effective heat sink for core cooling recovery. It is used in the EALs as an indicator of the potential loss of the RCS fission product barrier. In the PRA models, operator actions to diagnose the SGTR event are typically modeled in the same operator action to isolate the ruptured SG secondary side and terminate AFW to the ruptured SG. The SG narrow range level is also implicitly used in the PRA for two additional actions: maintaining SG water level to provide an effective heat sink and terminating feedwater flow to prevent SG overfill for tube rupture events. The PRA assessment in Appendix A indicates that SG level is an indication required for risk significant operator actions. Since the SG narrow

Table 9 Comparison of PAM Instrumentation			
Instrument	Plant Specific Technical Specifications	NUREG-1431	WCAP-15981
Power Range Neutron Flux	✔	✔	✔
RCS Pressure (Wide Range)	✔	✔	✔
Containment Pressure (Wide Range)	✔	✔	✔
Containment Isolation Valve Position	✔	✔	✔
Steam Generator Water Level (Wide Range)	✔	✔	✔
Core Exit Temperature	✔	✔	✔
Steam Generator Pressure	✔		✔
High Head SI Flow	✔		✔
Auxiliary Feedwater Flow	✔	✔	✔
RCS Hot Leg Temperature	✔	✔	
RCS Cold Leg Temperature	✔	✔	
Source Range Neutron Flux	✔	✔	
Containment Area Radiation (High Range)	✔	✔	✔
Condensate Storage Tank Level	✔	✔	
Pressurizer Level	✔	✔	✔
Containment Sump Water Level (Wide Range)	✔	✔	
RCS Subcooling Margin	✔		
Reactor Vessel Water Level	✔	✔	
Hydrogen Monitors	✔	✔	Note 1
Containment Sump Water Level (Narrow Range)	✔		
RWST Level (Wide Range)	✔		✔
Steam Generator Water Level (Narrow Range)	✔		
Spent Fuel Pool Exhaust Radiation (High Range)	✔		
Condenser Air Ejector (High Range)	✔		
Plant Vent Stack (High Range)	✔		
Steam Generator Blowdown Radiation	✔		
Steam Line Radiation	✔		
TDAFW Pump Exhaust Radiation	✔		
Pressurizer Pressure	✔		
PORV Position	✔		
PORV Block Valve Position	✔		
Pressurizer Safety Valve Position	✔		
Auxiliary Feedwater (AFW) Valve Position	✔		
Boric Acid Tank (BAT) Level	✔		
Containment Enclosure Negative Pressure	✔		
Containment Pressure (Narrow Range)	✔		
Intermediate Range Neutron Flux	✔		
Residual Heat Removal (RHR) Flow	✔		
Spray Additive Tank (SAT) Level	✔		

Note:
1. Hydrogen Monitors are not addressed in this report, since they are already addressed in the 50.44 Rulemaking Package (Reference 17)

The recommended Type and Class based on the current accident management usage discussed in this report, and the basis for that recommendation was included in the discussion of each indication. The summary of the recommended classifications are provided in the following Table 10 for those PAM indications that are recommended for inclusion in the Technical Specifications based on the current accident management usage discussed in this report. Table 11 provides a similar summary for key instrumentation that is currently in the PAM Technical Specification in NUREG-1431 and that is not recommended for inclusion in the revised PAM Technical Specifications.

Table 10 Regulatory Guide 1.97 Classification for Recommended PAM Technical Specification Instrumentation

Function	Typical Reg. Guide 1.97 Variable Type/Category[1]	WCAP-15981 Type/Category	Basis
1. Power Range Neutron Flux	B1	B1	Provides verification of automatic actuation of RPS – Type B. Provides direct information to verify accomplishment of the subcriticality safety function – Category 1.
2. Steam Generator Pressure	A1	A1	Provides information for operator action for SGTR break flow termination for which no automatic control is provided – Type A. Together with RCS pressure, provides information to verify that break flow through a ruptured SG tube is terminated thereby satisfying the inventory safety function – Category 1.
3. RWST Level	A1	D1	Provides information to indicate the continued operation of SI for continued inventory control – Type D. Provides information to indicate the need to refill the RWST to continue inventory control for SGTR and ISLOCA events – Category 1.[2]
4. High Head SI Flow	D2	B1	Provides verification of automatic actuation of SI – Type B. Provides direct information to verify the operation of SI to maintain the inventory safety function for core cooling – Category 1.
5. RCS Pressure (Wide Range)	A1	A1	Provides information for operator action for SGTR break flow termination for which no automatic control is provided – Type A. Together with SG pressure, provides information to verify that break flow through a ruptured SG tube is terminated thereby satisfying the inventory safety function – Category 1.
6. Containment Pressure (Wide Range)	C1	C1	Provides information to identify a fission product barrier challenge – Type C. Provides direct verification of containment cooling to maintain the containment fission product barrier safety function – Category 1.

Table 10 Regulatory Guide 1.97 Classification for Recommended PAM Technical Specification Instrumentation (cont.)

Function	Typical Reg. Guide 1.97 Variable Type/Category	WCAP-15981 Type/ Category	Basis
7. Penetration Flow Path Containment Isolation Valve Position	B1	B1	Provides verification of automatic actuation of Phase A and Phase B containment isolation – Type B. Provides direct verification of containment isolation to maintain the containment fission product barrier safety function – Category 1.
8. Containment Area Radiation (High Range)	A1	C1	Provides information to identify a fission product barrier challenge – Type C. Provides direct verification of satisfying the core cooling safety function – Category 1.
9. Pressurizer Level	A1	A1	Provides primary information needed to permit operators to take specified manual actions to terminate SI – Type A. Provides information related to satisfying the RCS inventory safety function to permit SI termination – Category 1.
10. SG Water Level (Wide Range)	D1	A1	Provides information for operator action maintaining a heat sink for which no automatic control is provided – Type A. Provides direct verification of satisfying the heat sink safety function – Category 1.
11. Core Exit Temperature	A1	A1	Provides information needed to permit the operators to take specified manual actions to initiate RCS depressurization – Type A. Provides direct verification of satisfying the core cooling safety function – Category 1.
12. AFW Flow	A1	B1	Provides verification of automatic actuation of AFW – Type B. Provides direct verification of satisfying the heat sink safety function – Category 1.

Note:

(1) Only the highest Reg. Guide 1.97 classification is shown in this table.

(2) If switchover to ECC recirculation is based on the RWST level indication rather than the RWST level alarm, it should be classified as a Type A variable rather than a Type D variable.

Table 11 Regulatory Guide 1.97 Classification for PAM Instrumentation Relocated to LCDs			
Function/No.	Typical Reg. Guide 1.97 Variable Type/Category	WCAP-15981 Type/ Category	Basis
1. Source Range Neutron Flux	B1	B3	Provides verification of automatic actuation of RPS – Type B. Provides diagnostics of continued subcriticality during RCS cooldown and depressurization – Category 3.
2. RCS Hot Leg Temperature	A1	B3	Provides information to indicate whether the core cooling safety function is being accomplished – Type B. Provides backup to the CETs – Category 3.
3. RCS Cold Leg Temperature	A1	B3	Provides information to indicate whether the core cooling safety function is being accomplished – Type B. Provides backup to the CETs – Category 3.
4. Reactor Vessel Water Level	B1	B3	Provides information to indicate whether the core cooling safety function is being accomplished – Type B. Provides backup to the CETs – Category 3.
5. Containment Sump Water Level (Wide Range)	A1	B2	Provides information to indicate whether the core cooling safety function can be accomplished when RWST switchover occurs – Type B. Provides information on the status of ECC recirculation delivery – Category 2.
6. Condensate Storage Tank Level	A1	B2	Provides information to indicate whether continued SG heat sink can be maintained – Type B. Provides in formation indicating long term AFW system operating status – Category 2.

Note:

Only the highest Reg. Guide 1.97 classification is shown in this table.

Table 13 Summary of Alternate PAM Instrumentation	
Primary Instrumentation	**Alternate Instrumentation**
SG Water Level (Wide Range)	SG Narrow Range Level AND Auxiliary Feedwater Flow Rate
Power Range Neutron Flux	Intermediate or Source Range Indications AND either the Rod Position Indicators OR Rod Bottom Lights
Containment Area Radiation (High Range)	Portable Radiation Monitors
High Head Safety Injection Flow	High Head Safety Injection Pump Amperage AND SI Pump Discharge or Header Pressure AND Automatic SI valve position
Auxiliary Feedwater Flow	Motor Driven Pumps: Pump Amperage AND Pump Discharge Pressure OR flow control valve (SG supply) position
	Turbine Driven Pump: Pump Discharge Pressure OR steam supply valve position AND flow control valve (SG supply) position

Power Range Neutron Flux

The power range neutron flux indication is used immediately following an accident or receipt of a reactor trip signal. For the purposes of providing an indication of the failure to achieve subcriticality, which would result in operator actions to manually trip the reactor, the power range neutron flux indication is the only direct means of providing this information.

If the power range neutron flux indication is not available, an alternate method of monitoring subcriticality is a combination of either the intermediate range or source range neutron flux indications, AND either the rod bottom lights or rod position indicators. The rod bottom lights and rod position indicators are the primary alternate indications used in the EOPs to verify the accuracy of the power range neutron flux indication. If the control rods are fully inserted, initial subcriticality is ensured by the plant design basis. Therefore, these alternate indications can also provide the information necessary for the operators to determine the need to initiate a manual reactor trip. The intermediate and source range indications are the primary backup indications used in the Functional Restoration Guidelines for diagnosis of a potential loss of core shutdown (once initial subcriticality is reached). Thus, the intermediate and source range indicators can provide an alternate to the power range monitor to diagnose continued subcriticality. The combination of either the source or intermediate range neutron flux monitors and either the rod bottom lights or rod position indicators provide an alternate indication of subcriticality to the power range neutron flux monitor.

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The power range neutron flux reactor trip function is required to be Operable in Modes 1 and 2. The PRA typically shows that power range neutron flux is a key indication for accident management operator actions to initiate manual reactor trip to bring the reactor to a subcritical condition, which is a keff of < 0.99. This is consistent with the keff of > 0.99 specified as the reactivity condition for Mode 2 and for power operation in Mode 1. Subsequent operator actions (in Mode 3 after a reactor trip) to assure that the reactor remains in subcritical state, where the power range neutron flux indication may no longer be operable, such as during RCS depressurization, were not determined to be important for long term core cooling. Therefore, for the required PAM indication function (i.e., confirming a reactor trip from Modes 1 and 2, the Power Range Neutron Flux indication is only required to be Operable in Modes 1 and 2. This also makes the PAM Technical Specification Mode of applicability for the Power Range

Neutron Flux indication consistent with the corresponding Mode of applicability of the Reactor Trip System Instrumentation Technical Specification.

SG Pressure

SG pressure is used following an accident or receipt of a reactor trip signal to indicate secondary side integrity. It is also used as the target pressure for RCS cooldown and depressurization to terminate the break flow following a SGTR. There is no reliable alternate indication for determining the SG pressure. Therefore, no alternate indication is proposed in the event that SG pressure indication is unavailable.

RWST Level

RWST level indication is required following an accident or receipt of a reactor trip signal. The RWST level instrumentation provides an indication of the need to initiate RWST makeup for accident sequences in which most of the discharge of reactor coolant is to locations outside of the containment. The narrow range RWST level indication only has a sufficient range to indicate the RWST level associated with the Technical Specification requirement for the minimum RWST level and does not extend to the level needed to indicate the need for RWST refill following an accident. Thus, there is no alternate instrumentation to support the operator action to refill the RWST to provide continued makeup to the RCS for long term core cooling if the instrumentation is unavailable.

High Head Safety Injection Flow

There is typically only one channel of High Head SI Flow instrumentation per train to provide indication of SI flow for the diagnosis of the need for operator actions to manually initiate an SI signal or to start the high head SI pumps in the event that automatic SI initiation does not occur. An alternate method of monitoring flow from the high head SI pumps can be inferred from the high head SI pump amperage and the high head SI pump discharge or header pressure indications, and the automatic SI valve position indication. All of these indications are typically used in the EOPs to provide verification of the satisfactory operation of the High Head SI pumps. Since each indication only provides a portion of the verification of High Head SI flow, all three indications are required to provide a high degree of confidence of adequate High Head SI flow if the High Head SI flow rate indication is inoperable.

RCS Pressure (Wide Range)

RCS pressure indication is used for determining RCS pressure and RCS subcooling following an accident or receipt of a reactor trip signal. The pressurizer pressure indication does not have sufficient range to satisfy any of the indications that prompt important operator actions based on RCS pressure. Therefore, no alternate indication is proposed in the event that RCS pressure indication is unavailable.

Containment Pressure (Wide Range)

Containment pressure indication is required following an accident or receipt of a reactor trip signal. The containment pressure wide range indication provides information for the determination of an inadequate containment cooling condition and for the determination of a challenge to the containment pressure retaining integrity. The narrow range containment pressure instrumentation, which only extends to the design basis pressure, could be used to determine an inadequate containment cooling condition, however it does not have a sufficient range to be useful in determining the potential of a challenge to containment integrity due to overpressurization. Therefore, no alternate indication is proposed if the containment pressure indication is unavailable.

Penetration Flow Path Containment Isolation Valve Position

The Penetration Flow Path Containment Isolation Valve Position indication provides a direct indication of a failure to completely isolate containment following the receipt of a containment isolation signal. In penetrations that contain two motor operated isolation valves, the indication from each valve is typically provided by separate electric trains so that in the event of a failure of one train of electric power, the indication from the other train would be available. The important operator action taken from this information is for manual containment isolation in the event that automatic isolation does not occur, and also for input to the declaration of the appropriate EAL condition. This instrumentation is the only means of confirming that all containment isolation valves are in the isolation position following an automatic containment isolation signal. Therefore, no alternate indication is proposed if the penetration flow path containment isolation valve position indication is unavailable.

Containment Area Radiation (High Range)

The containment area radiation provides an indication of a loss of one or more fission product barriers. In the event that both required channels are unavailable, an alternate method of monitoring is the use of portable radiation monitors outside of containment to infer the order of magnitude of the level of radiation inside the containment. The Core Damage Assessment methodology in WCAP-14696-A shows that the details of the accident sequence can account for differences in containment radiation levels that are an order of magnitude different. Portable radiation monitors are capable of providing information for an order of magnitude estimate.

Pressurizer Level

The pressurizer level indication is used for determining pressurizer level for SI termination following an accident. There are no other means of inferring pressurizer level in the event that the pressurizer level indication is unavailable. Therefore no alternate indication is proposed.

Steam Generator Water Level (Wide Range)

The SG level indication is used to maintain a heat sink and for the diagnosis of a SGTR accident, and can be fulfilled by one channel of SG narrow range instrumentation per SG is available. The indication for the initiation of bleed and feed requires that all SGs indicate a very low level. An alternate indication for SG level Wide Range is a combination of one SG level Narrow Range channel, and the AFW flow rate to that SG. This combination can be used to infer that an inventory is available in the SG in place of the SG level wide range indication. The SG narrow range level indication provides a suitable alternate for the diagnosis functions of the SG level wide range indication except for the initiation of bleed and feed cooling when the SG level approaches dryout. Bleed and feed cooling is only required to be implemented if the level in all SGs is below the setpoint level (which is near the dryout stage). If the SG level wide range indication is inoperable, a suitable alternate indication for the initiation of bleed and feed cooling would be a SG level narrow range indication off-scale low in ALL SGs AND an AFW flow rate below that needed for decay heat removal (which is already specified in the EOP's). Therefore, the combination of SG narrow range level and AFW flow rate adequately serve as an alternate if the SG wide range indication is inoperable.

RCS Temperature

RCS temperature indication is required following an accident for operator determination of RCS subcooling for both RCS cooldown and depressurization, and for SI termination. This PAM indication is provided by the CETs. The required number of CET channels is discussed under the core temperature indication requirements below.

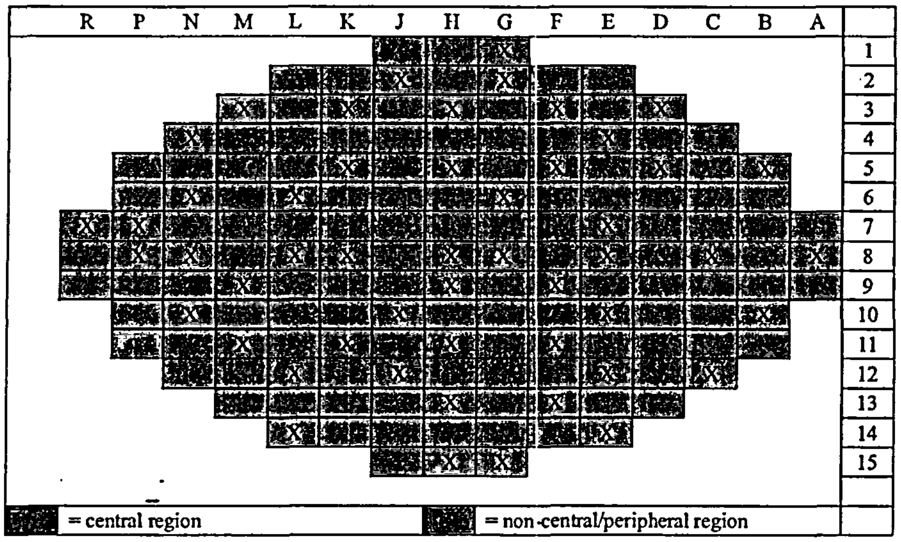

Figure 1 Typical Core Exit Thermocouple Locations for a Three Loop Plant

The only alternate indication used in the WOG ERGs for the indication of inadequate core cooling is the reactor vessel level indication. However the reactor vessel level indication is not used to indicate the need to transition from the EOPS to the SAMG; only the CET indications provide an operator cue for this transition. Since the CETs are used for important operator actions in the SAMG, it is concluded that there are no appropriate alternate indications for the CETs.

Auxiliary Feedwater Flow Indication

The AFW Flow instrumentation provides an indication of AFW flow that supports the diagnosis of the need for operator actions to manually initiate an AFW signal or start AFW pumps in the event that automatic AFW initiation does not occur. The AFW Flow instrumentation provides the most direct indication of AFW flow to allow the diagnosis of the need for operator actions to manually start the AFW pumps to initiate an alternate source of feedwater. An alternate method of inferring AFW flow rate for the motor driven pumps can be provided by the AFW pump amperage AND the AFW pump discharge pressure OR the flow control valve position (SG supply) indications. An alternate method of inferring AFW flow rate for the turbine driven pump, is the AFW pump discharge pressure OR the steam supply valve position AND the flow control valve position (SG supply) indications.

All of these indications are typically used in the EOPs to provide verification of the satisfactory operation of the AFW pumps. Since each indication may only provide a portion of the verification of AFW flow, some combination of the alternate indications, as shown in Table 12, provides a high degree of confidence of adequate AFW flow if the AFW flow rate indication is inoperable.

These alternate indications are appropriate since the risk significant action is to provide an alternate SG feed source if no AFW pumps are available.

The additional plant specific PAM instrumentation that is identified in Table 9, or other plant specific PAM instrumentation that is not identified in Table 9, that does not satisfy the requirements for inclusion in the Technical Specifications based on the methodology contained in this report can also be relocated from the Technical Specifications to LCDs.

The generic list of PAM instrumentation proposed to be included in Technical Specification 3.3.3 of NUREG-1431, and those instruments proposed to be relocated from plant specific Technical Specifications to LCDs must be confirmed on a plant specific basis by reviewing the plant specific DBA analyses, PRA, EOPs, SAMGs, and EPIP.

8 IMPLEMENTATION

The plant specific implementation of this methodology contained in this report requires a plant specific evaluation of the accident management application of PAM instrumentation contained in the: 1) Design Basis Accidents, 2) Emergency Operating Procedures, 3) Probabilistic Risk Assessment, 4) Severe Accident Management Guidelines, and 5) Emergency Plan as discussed in this report.

The generic list of PAM instrumentation proposed to be included in Technical Specification 3.3.3 of NUREG-1431, and those instruments proposed to be relocated from the plant specific Technical Specifications to LCDs must be confirmed on a plant specific basis by reviewing the plant specific DBA analyses, PRA, EOPs, SAMGs, and EPIP.

The overall process to be used by licensees to identify the PAM instrumentation that should be included in the Technical Specifications is provided in Figure 2. This process is identical to that described in this report, except that plant specific information would be used in place of generic information.

As discussed in Section 3.1, the licensee should ensure that the PRA is technically adequate for this application. PRA technical adequacy is addressed through the PRA peer reviews and self assessments using a variety of guidance, including the American Society of Mechanical Engineers (ASME) PRA Standard (Reference 7), Nuclear Energy Institute (NEI) PRA Peer Review Process Guidance (Reference 8) and/or Regulatory Guide 1.200 (Reference 9). The more extensive PRA technical adequacy requirements contained in References 7 and 9, while assuring a more robust PRA, are not required for this application since the determination of the PAM Technical Specification instrumentation does not rely solely on the PRA and the CDF and LERF values determined from the PRA model.

The first step in the process is to identify all operator actions that are assumed in DBA analyses using the criteria in Table 5. These operator actions satisfy Criterion 3 of 10 CFR 50.46 in that no automatic actuation of equipment is included in the plant design for these actions.

The next step is to identify the risk important operator actions from the plant PRA using the criteria in Table 5. The RAW and F-V risk importance measures with appropriate numerical values can be used to identify the risk important operator actions. For consideration of external events (e.g., fire and seismic initiating events), if a quantitative PRA is available, the risk importance of operator actions can be identified as in the internal events PRA. For qualitative external events risk assessments, the results of the assessments can also be used to identify important operator actions by identifying operator actions required for risk important external events or safe shutdown equipment lists. As discussed in Appendix A of this report, the risk important operator actions are expected to be identified from the at-power, internal events PRA. The risk important operator actions can be identified from the RAW and F-V values. As discussed in Section A.4 of this report, a RAW value greater than 2.0 or an F-V value greater than 0.05 should be used to define risk important operator actions.

The next step is to identify the instrumentation associated with the important design basis and PRA operator actions. This step establishes the relationship between the instrument and the associated human actions. This would typically involve the use of the plant emergency and off-normal / abnormal procedures to identify any instrumentation cues for initiating these actions, as well as instrumentation cues used to confirm that the operator action has been successfully completed.

The instrumentation required to support operator actions from the SAMG and the E-Plan would be identified separately since neither the SAMG nor the E-Plan is typically modeled in the PRA using the criteria in Table 5 of this report. As discussed in earlier in this report, the instrumentation used to support critical SAMG operator actions are those that identify challenges to the containment fission product boundaries. From the E-Plan, the Core Damage Assessment is important because it is used to project offsite doses from an accident and instrumentation used to provide the core damage assessment or the dose projections are important. The EALs are important because they support notification of the offsite authorities and provide a uniform method of ranking the severity of the accident; only the instrumentation that supports the declaration of a General Emergency is considered to be risk important. The generic determination for the Core Damage Assessment determination in this report was based on the use of the approved methodology in WCAP-14696-A. If a licensee has used a different methodology then an assessment of the key indications that support the core damage assessment should be performed based on the actual methodology used.

The final step is to identify the minimum set of instrumentation that supports the important actions identified in the previous steps. In some cases, such as steam generator level, some actions can be cued from more than one set of instrumentation, while others can only be cued from specific instrumentation. This step would therefore focus on the minimum set required to support the key operator actions.

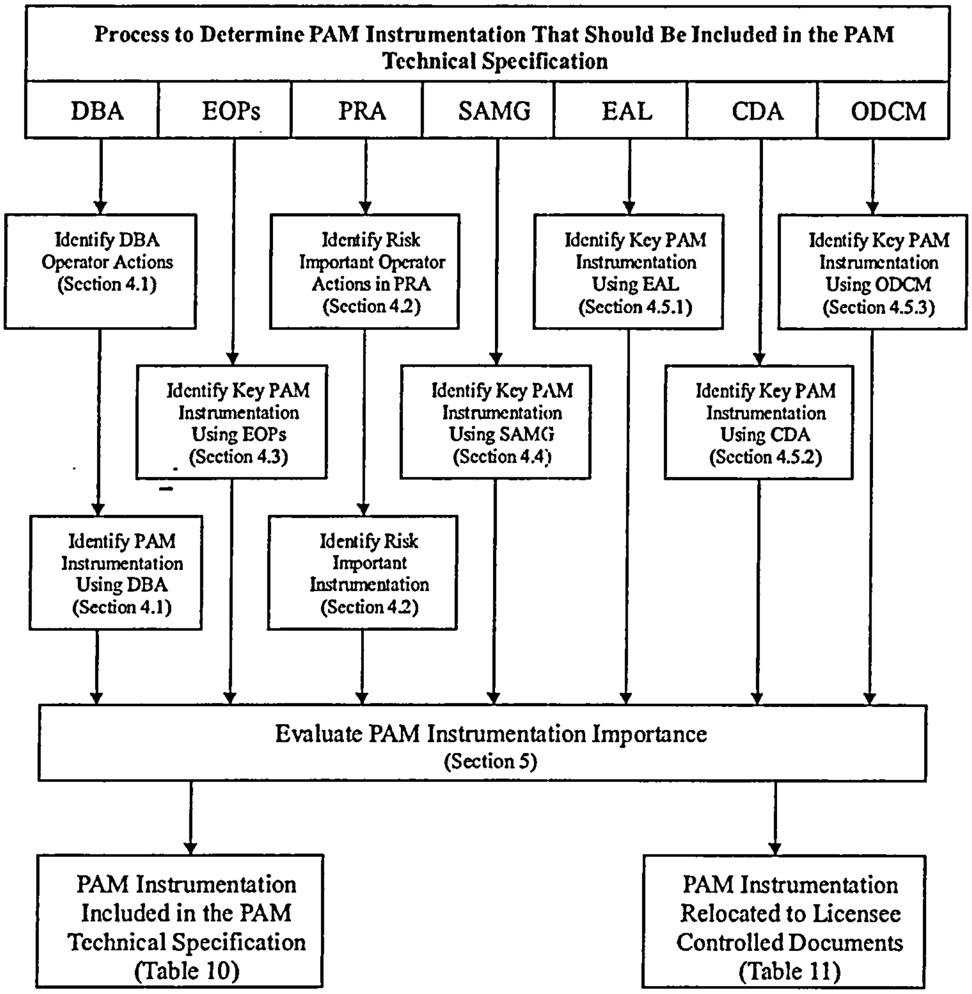

Figure 2 Process to Determine PAM Instrumentation That Should Be Included in the PAM Technical Specification

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APPENDIX A
INSTRUMENTATION IMPORTANCE IN PRAs

A.1 BACKGROUND

In the early 1980's several plant specific Probabilistic Risk Assessments (PRAs) were performed (e.g., Zion Units 1 and 2, Indian Point Units 2 and 3) to resolve regulatory concerns related to severe accidents. Several other PRAs were completed throughout the 1980's. The comprehensive NUREG-1150 study was completed in the late 1980's using five reference plants to characterize severe accident risks. These studies identified plant specific design and operational differences as a primary reason for significant differences in the severe accident risks. In this context, severe accident risks are a measure of probability and consequences.

Several measures of severe accident risks have been identified and subsequently used as risk "metrics." The most common of these is core damage frequency (CDF) and large early release frequency (LERF). Also, "importance measures" were developed to indicate the contribution of systems, components, and operator actions to these risk metrics:

- The Risk Achievement Worth (RAW) is a measure of the increase in risk (CDF or LERF) if the system, component, or operator action is assumed to fail with a probability of unity. It is defined as the ratio of the CDF or LERF with failure of the component set to unity and the CDF or LERF using the best estimate failure value.

- The Risk Reduction Worth (RRW) is a measure of the decrease in risk if the failure probability is set to zero. It is defined as the ratio of the CDF or LERF with failure of the component set to zero and the CDF or LERF using the best estimate failure value.

- The Fussell-Vesely (F-V) measure is a derivation of the RRW and is defined as, F-V=1+1/RRW.

Because of the potential for plant specific differences to control the severe accident risks, each plant was required to perform an Individual Plant Examination (IPE) in response to NRC Generic Letter 88-20 in the late 1980's. The purpose of the IPE was to identify any plant specific vulnerabilities (weaknesses) that would dominate the risk profile of the plant. In some cases, plant modifications were made to address specific vulnerabilities that were determined to be unacceptable. While a quantitative PRA was required to quantify the risks associated from internally initiated accidents from an at-power plant operating state, GL 88-20 also required at least a qualitative risk assessment of external initiating events, such as seismic and fire. This is commonly referred to as an IPEEE.

Subsequently, each plant's IPE has evolved into a Probabilistic Risk Assessment (PRA) study. The primary difference between the IPE and the PRA is in the depth to which the plant is modeled; the IPE only modeled the plant features necessary to identify vulnerabilities, while the PRA models include many more systems and components that have a somewhat lower overall contribution to risk. These plant specific PRA models have been used to address regulatory and plant operational differences to ensure that the severe accident risks remain low during all phases of plant operations.

As the PRA models have become more mature and confidence has been gained in their application, the PRA has been used, along with deterministic analyses and engineering judgment, to relax unnecessarily restrictive regulatory requirements. The NRC has developed guidance on the use of PRA to change regulatory requirements in the form of Regulatory Guide 1.174. This approach has been termed risk-informing regulatory requirements. This regulatory guide uses the change in CDF and LERF due to the proposed change in regulatory requirements, along with importance measures to determine, in part, whether such a regulatory requirement change is acceptable. This process is also being used in the development of the proposed 10 CFR 50.69 rulemaking to determine the risk informed repair and replacement treatment requirements.

A.2 INSTRUMENTATION MODELING IN PRAs

Instrumentation is typically not modeled explicitly in the PRA. Rather, assumptions about the instrumentation availability and reliability are typically included in other PRA models. For example, the reliability of instrumentation to generate a reactor trip or SI signal is typically included in the overall reactor trip or SI signal model. The reactor trip or SI model combines the instrumentation failure with many other potential failure modes to determine the reliability of the reactor trip of SI function itself.

In the case of Post Accident Monitoring (PAM) instrumentation, the assumptions regarding its availability and reliability are most often included as part of the Human Reliability Analysis (HRA). In other words, the failure of the instrumentation is modeled as one of the causes of a failure of a required human interaction to achieve a safe, stable, plant state. Since the PAM instrumentation does not generate any automatic signals, the importance of PAM instrumentation can be investigated by identifying the operator actions that rely on instrumentation and determining the risk importance (e.g., RAW and F-V) of that operator action.

A.3 IMPORTANCE DATA FROM PRAs

In 1997, the WOG authorized a program for the collection of important features and results from Westinghouse NSSS plant specific PRA studies into a comprehensive database. This database was subsequently completed as a proprietary product for WOG utility use in 1999. The database was constructed by requesting that each Westinghouse NSSS licensee provide their current PRA values for certain parameters that were thought to be the more dominant contributors to core damage. In the case of HRA results, a prescribed set of operator actions were defined for the primary input based on those operator actions that were identified to be the most important to the PRA results. The database also contains other important operator actions from utility PRAs, as provided by those utilities.

A database update was conducted in 2001, and completed for WOG utility use in 2002, to reflect newer PRA results. The new results were a product of significant recent changes in utility PRAs as a result of utilities upgrading the PRA models for both risk informed applications and to respond to the PRA Peer Review findings.

The 1999 PRA survey results were collected for both RAW and F-V values for operator actions modeled in the PRA. However, the PRA information collected in the 2002 survey only included F-V values of operator actions, since the importance measures for operator actions generally focus on improvements in operator actions via training and/or procedure modifications. However, the RAW importance measure is more appropriate for the evaluation of the PAM instrumentation based on the potential decrease in equipment reliability if it is removed from the Technical Specifications. In the 2002 survey, it was not foreseen that the operator action importance measures would be used to investigate the reliability of the information upon which the operator actions are based.

To address the issue of operator action naming, common sets of operator action titles were developed from the database information, as shown in Tables A-1, A-2 and A-3. Using these standard operator actions, the risk importance of the operator actions over all Westinghouse NSSS plants is shown in Tables A-1 through A-3. Table A-1 summarizes the F-V importance measure results from information provided in the 2002 database update. Table A-2 provides the F-V importance measures from the 1999 database; Table A-3 provides the RAW values from the 1999 database. The information provided in Tables A-1 through A-3 shows the maximum and minimum values for the risk importance measures for each operator action reported in the databases, along with the median value based on all of the plants that provided a value. The mean value is not included, because it is typically skewed by one or two very high RAW and F-V values in the database.

A.4 CRITERIA FOR RISK IMPORTANCE

The EPRI PSA Applications Guide (Reference 18) suggests that a component has a high risk significance if the F-V value is greater than 0.05 or the RAW value is greater than 2.0. The use of F-V and RAW to identify risk important systems structures and components has been used in Section 5.1 of NEI 00-04 (Reference 19), which is endorsed by the NRC in Regulatory Guide 1.201 (Reference 20). The system level importance measure criteria for F-V from Reference 18 are applicable here based on two observations: 1) the operator action failure disables an entire system, as opposed to a component failure that may only contribute to a system failure, and 2) instrumentation failures are only a portion of the operator action failure, with the remainder being made up of operator errors of omission and commission in reading instrumentation and taking the appropriate actions. However, risk importance thresholds cannot be used as absolute criteria above which SSCs can be considered to be clearly risk-significant and below which they can accepted as low in safety-significance. Rather, they are screening devices that provide insights as to what may or may not be important to safety for any given plant or system design.

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At this point, a discussion of the common usage of the risk importance measures is in order. Risk Achievement Worth defines the importance of a PRA parameter by comparing the overall risk results (e.g., overall core damage) with the parameter at its nominal value, to the overall risk if the parameter is totally unreliable (e.g., always failed). Fundamentally, the Risk Achievement Worth has little to do with the design or reliability of a component itself, but relies heavily on the defense-in-depth available in the form of redundant SSCs to mitigate the effects of the loss of the component. On the other hand, the F-V more directly relates to the reliability of a component by suggesting the impact on risk from improvements in reliability.

Table A-1 2002 PRA Survey Results Operator Action Risk Reduction Worth*

Operator Action	Max	Min	Median
Align Alternate Cooling to Charging Pumps	1.53	1.008	1.05
Restore AC Power	1.59	1.00	1.04
Restore Equipment Following AC Power Recovery	1.17	1.02	1.05
Re-Align AFW	1.10	1.00	1.02
Align Alternate Feedwater Source	1.10	1.01	1.05
Perform Remote Shutdown	1.20	1.10	1.12
Perform Bleed and Feed	1.20	1.00	1.02
Restore CCW	1.06	1.01	1.03
Restore Instrument Air	1.08	1.00	1.03
Align Emergency Boration	1.02	1.00	1.01
Transfer to Cold Leg Recirculation	1.59	1.03	1.05
Isolate Stuck Open Pressurizer PORV	1.04	1.004	1.01
Isolate Ruptured SG	1.05	1.007	1.03
Reactor Shutdown for ATWS	1.11	1.005	1.02
Manual SI	1.23	1.006	1.02
Establish Normal RHR	1.05	1.006	1.03
RCS Cooldown and Depressurization	1.19	1.00	1.04
Refill CST	1.09	1.07	1.08
Refill RWST	1.12	1.01	1.07
RCS Cooldown for SGTR	1.08	1.004	1.06
Restore Service Water	1.17	1.001	1.03
Control AFW Flow to Maintain SG water level	1.06	1.007	1.04
Terminate SI for SS Break	1.07	1.001	1.02
Terminate SI for SGTR	N/R	N/R	N/R

Note:
N/R = Not reported in the 2002 survey.
* Values in the database are given as Risk Reduction Worth which is related to F-V by:
RRW = 1 - (1 - F-V).

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Table A-2 1999 PRA Survey Results Operator Action Risk Reduction Worth*			
Operator Action	**Max**	**Min**	**Median**
Align Alternate Cooling to Charging Pumps	1.29	1.000	1.042
Restore AC Power	1.085	1.002	1.023
Restore Equipment Following AC Power Recovery	1.10	1.000	1.012
Re-Align AFW	1.22	1.000	1.005
Align Alternate Feedwater Source	1.10	1.005	1.019
Perform Remote Shutdown	1.29	1.020	1.125
Perform Bleed and Feed	1.29	1.008	1.015
Restore CCW	1.06	1.000	1.015
Restore Instrument Air	N/R	N/R	N/R
Align Emergency Boration	1.03	1.000	1.000
Transfer to Cold Leg Recirculation	1.59	1.000	1.029
Isolate Stuck Open Pressurizer PORV	N/R	N/R	N/R
Isolate Ruptured SG	1.38	1.000	1.005
Reactor Shutdown for ATWS	1.04	1.000	1.000
Manual SI	1.02	1.005	1.008
Establish Normal RHR	1.03	1.013	1.015
RCS Cooldown and Depressurization	1.13	1.000	1.016
Refill CST	N/R	N/R	N/R
Refill RWST	1.42	1.001	1.071
RCS Cooldown for SGTR	N/R	N/R	N/R
Restore Service Water	1.45	1.000	1.02
Control AFW Flow to Maintain SG water level	N/R	N/R	N/R
Terminate SI for SS Break	1.05	1.000	1.000
Terminate SI for SGTR	1.10	1.000	1.002

Note:
N/R = Not reported in the 1999 survey.
* Values in the database are given as Risk Reduction Worth which is related to F-V by:
RRW = 1 - (1 - F-V).

Deleted: (Using FV Importance Measure)

In PRA applications, the RAW is typically used to assess the conditional risk during the time that a component is assumed to be removed from service. If the component is in service, then the components with the highest Risk Achievement Worth are those that should be considered for protecting against failure or avoiding additional activities that could remove them from service or render them inoperable. Risk Achievement Worth can be a useful tool in configuration risk management in this regard. In this application, the Risk Achievement Worth measure of importance can be an indicator for maintaining the current reliability of the instrumentation under consideration. Components ranking high in Risk Achievement Worth are those which potentially can result in the greatest increase in risk if their reliability is allowed to degrade. These components should be focused on in the monitoring of reliability and availability efforts, as well as other potential special treatment requirements. Less benefit is expected to be derived by focusing on systems and components ranking low in Risk Achievement Worth, since greater uncertainty can be tolerated in their performance due to the limited impact they are likely to have on risk.

Application of the Fussell-Vesely measure of importance includes the identification of SSCs that may be candidates for modification or improvement such that the overall risk can be lowered if the failure probability were reduced. Components ranking high in Fussell-Vesely are those at which efforts to improve the reliability or redundancy may have the greatest benefit. Components ranking low in Fussell-Vesely importance are not necessarily the best components on which to focus such efforts, since even if they were to be made completely reliable, they would only have a limited impact on overall risk.

It must be recognized when calculating either of these importance measures that it is physically impossible to make a component perfectly reliable (as is assumed for the Fussell-Vesely measure of importance) and it is highly unlikely that a component will always fail when called upon to perform its function or will always be out of service (as is the case for Risk Achievement Worth). In this regard, the values derived for each of these measures of importance should be considered as extremes or at least bounding in their characterization of the impact of the individual component or system on risk.

A.5 ASSESSMENT OF OPERATOR ACTION IMPORTANCES

The data summary in Tables A-1 through A-3 reveals that there is significant variability in the risk significance of many operator actions from plant to plant. That is, the risk importance of a particular operator action, based on RAW or F-V, may be significantly different from one plant to another. There are a number of reasons for this, including:

- Differences in the HRA models, including differences in the human error probabilities assigned to various actions,
- Differences in the manner in which operator actions are grouped in the HRA model, and
- Differences in the contribution to core damage for a given operator action due to plant design and plant specific equipment reliability factors.

A comparison the F-V values reported in the 1999 and the 2002 surveys shows that there is not a significant difference in the results. That is, the operator actions with high F-V values in the 1999 survey also had high F-V values in the 2002 survey. The same conclusion can be drawn with respect to the low

F-V values; those operator actions with low F-V values in the 1999 survey also had low F-V values in the 2002 survey. Although RAW was not reported in the 2002 survey, it is assumed that the RAW values would also follow this same trend.

Therefore, the use of the operator action RAW values from the 1999 PRA survey, as shown in Table A-3 are a valid basis for assessing the importance of instrumentation for accident management.

From Table A-3 the operator actions with the highest RAW values, in descending order based on the median values for Westinghouse NSSS plants, are:

- Transfer to Cold Leg ECC Recirculation,
- RCS Cooldown and Depressurization,
- Manual Safety Injection,
- Restore AC Power,
- Perform Remote Shutdown,
- Re-align Auxiliary feedwater,
- Perform Bleed and Feed,
- Restore Component Cooling Water,
- Align Alternate Cooling to Charging Pumps,
- Isolate Ruptured SG,
- Align Alternate Feedwater Source
- Restore Service Water,
- Restore Equipment Following AC Power Recovery,
- Refill RWST,
- Terminate SI (SGTR and Secondary Side Breaks),
- Align Emergency Boration, and
- Reactor Shutdown for ATWS.

From these operator actions identified above, several can be eliminated based on the lack of instrumentation required to successfully complete the actions. The operator actions eliminated from further consideration are:

- Restore AC Power – This action is based on plant Abnormal Operating Procedures. The only instrumentation required for this action is the emergency bus voltage, which is an indicator that the action has been successfully completed. Since the successful completion of the operator action for restoration of a.c. power is not dependent on a specific indication that is provided by plant instrumentation, there is no potential post accident monitoring implication.

- Perform Remote Shutdown – The requirements for instrumentation at the remote shutdown panel are contained in the Remote Shutdown System Technical Specification, and are not PAM instrumentation.

- Restore Component Cooling Water (CCW) – This action is based on plant Abnormal Operating Procedures. The diagnosis of a fault in the CCW system and subsequent operator actions to restore CCW are based on the failure in a normally operating system. The failure of the system would be indicated in the control room by multiple indication and alarms. As such, no essential "key" parameter indication exists, since the operator action is based on the status of the entire system. The only instrumentation required for this action is the CCW flow and temperature, which is an indicator that the action has been successfully completed. Since this is not an action required to diagnose a condition that could lead to core damage that has a high risk significance, it does not satisfy Criterion 4 of 10 CFR 50.36 (c)(2)(ii) and therefore should not be included in the PAM Technical Specification.

- Align Alternate Cooling to Charging Pumps – This action is based on plant Abnormal Operating Procedures for loss of Component Cooling function to the charging pumps. The diagnosis of the loss of CCW and subsequent recovery actions are discussed above. The re-alignment of cooling to the charging pumps is a direct consequence of the diagnosis of a loss of CCW and is not based on any specific additional instrumentation indications. Since this is not an action required to diagnose a condition that could lead to core damage that has a high risk significance, it does not satisfy Criterion 4 of 10 CFR 50.36 (c)(2)(ii) and therefore should not be included in the PAM Technical Specification.
- Restore Service Water (SW) – The diagnosis of a fault in the SW system and subsequent operator actions to restore SW are based on the failure in a normally operating system. The failure of the system would be indicated in the control room by multiple indication and alarms. As such, no essential "key" parameter indication exists, since the operator action is based on the status of the entire system. The only instrumentation required for this action is the SW flow and temperature, which is an indicator that the action has been successfully completed. Since this is not an action required to diagnose a condition that could lead to core damage that has a high risk significance, it does not satisfy Criterion 4 of 10 CFR 50.36 (c)(2)(ii) and therefore should not be included in the PAM Technical Specification.
- Restore Equipment Following AC Power Recovery – This action is based on the plant Emergency Operating Procedures for Loss of All AC Power. This operator action follows the operator actions to restore a.c. power to the vital bus(es). An indication of successful restoration of a.c. power to a vital bus is the bus voltage. Various instrumentation are also available to indicate that actions to restore equipment have been successfully completed (e.g., pump amperage and flow). The only unique indication that equipment can be restored to a vital a.c. bus is the bus voltage. The vital bus voltage requirements are addressed by the Distribution Systems Technical Specification and are not PAM instrumentation.

It is also noted that although reactor coolant pump (RCP) seal LOCAs are an important contributor to core damage for Westinghouse PWRs, there are no operator actions modeled in the PRA to protect the RCPs from an RCP seal LOCA. The plant specific off-normal / abnormal procedures provide guidance for restoring seal cooling for those sequences that are susceptible to RCP seal LOCAs (which are all sequences involving a loss of all RCP seal cooling). However, if RCP seal cooling is not quickly re-established, then the procedures typically instruct the operators not to re-establish RCP seal cooling in order to avoid additional RCP seal damage due to thermal shock. Thus, there are no risk significant operator actions for preventing an RCP seal LOCA.

The next step in the assessment is to relate the PAM instrumentation to the operator actions modeled in the PRA. The instrumentation utilized for each operator action was identified by reviewing the detailed PRA models for several plants and confirming these results with an independent review of the generic WOG Emergency Response Guidelines, upon which all of the WOG plant Emergency Operating Procedures are based. The results of this assessment are shown in Table A-4.