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AEP
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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Stop O-P1-17
Washington, DC 20555-0001

Donald C. Cook Nuclear Plant Units 1 and 2
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION FOR LICENSE AMENDMENT REQUEST TO EXTEND REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM SURVEILLANCE TIME REQUIREMENTS AS EVALUATED IN WCAP-15376 (TAC Nos. MB6324 and MB6325)

Reference:

1) Letter from J. E. Pollock, Indiana Michigan Power Company, to U. S. Nuclear Regulatory Commission Document Control Desk, "Donald C. Cook Nuclear Plant Units 1 and 2 Docket Nos. 50-315 and 50-316 License Amendment Request to Extend Reactor Trip System and Engineered Safety Features Actuation System Surveillance Requirements as Evaluated in WCAP-15376," AEP:NRC:2311, dated August 30, 2002

2) Letter from W. H. Ruland, Nuclear Regulatory Commission, to R. H. Bryan, Westinghouse Owners Group, "Acceptance for Referencing of Topical Report WCAP-15376-P, Rev. 0, 'Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times' (TAC. No. MB0983)," dated December 20, 2002

3) Westinghouse Topical Report WCAP-15376-P-A, "Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times," dated March 2003

A001

4) Letter from J. E. Pollock, Indiana Michigan Power Company, to U. S. Nuclear Regulatory Commission Document Control Desk, Supplement to License Amendment Request to Extend Reactor Trip System and Engineered Safety Features Actuation System Surveillance Requirements as Evaluated in WCAP-15376," AEP:NRC:3311, dated February 27, 2003

5) Letter from H. K. Chernoff, Nuclear Regulatory Commission, to A. C. Bakken III, I&M, "Donald C. Cook Nuclear Plant, Units 1 and 2 - Request for Additional Information Regarding, 'License Amendment Request to Extended Reactor Trip System and Engineered Safety Features Actuation System Surveillance Time Requiremnent as Evaluated in WCAP-15376 (TAC MB6324 and MB6325),'" dated March 27, 2003

This letter provides Indiana Michigan Power Company's (I&M's) response to a Nuclear Regulatory Commission (NRC) request for additional information (RAI) regarding a proposed license amendment to revise the Donald C. Cook Nuclear Plant (CNP) reactor trip system (RTS) and engineered safety features actuation system (ESFAS) surveillance requirements. This letter also documents the results of I&M's review of WCAP-15376-P-A, dated March 2003, against the evaluations in the proposed license amendment.

By Reference 1, I&M, the licensee for CNP Units 1 and 2, proposed to amend Appendix A, Technical Specifications (TS), of Facility Operating Licenses DPR-58 and DPR-74. I&M proposed to revise the CNP RTS and ESFAS surveillance requirements based on the evaluation in WCAP-15376-P, Revision 0, "Risk-Informed Assessment of the RPS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times." The proposed changes adopt the NRC approved Technical Specification Task Force (TSTF) Traveler TSTF-411, Revision 1, "Surveillance Test Interval Extension for Components of the Reactor Protection System." By Reference 2, the NRC issued a Safety Evaluation (SE), documenting the acceptability of referencing WCAP-15376-P in licensing applications. The NRC's SE was incorporated into the approved version of this WCAP, WCAP-15376-P-A (Reference 3) in March 2003. In Reference 4, I&M supplemented the amendment request to respond to the conditions and limitations stipulated in Reference 2 and withdrew TS changes proposed in Reference 1 that were not bounded by WCAP-15376-P. Reference 5 transmitted an NRC RAI regarding the proposed amendment.

I&M has reviewed the approved version of WCAP-15376-P and found that evaluations and reviews performed in support of References 1 and 4 are unaffected by the changes that were incorporated into WCAP-15376-P-A, dated March 2003.

Enclosure 1 provides an affirmation pertaining to the statements made in this letter. Enclosure 2 provides the response to the NRC RAI. Questions 3 and 4 of the NRC RAI identified that some of the proposed frequency notations for the TS surveillances would allow a longer surveillance interval than evaluated by WCAP-15376-P should the maximum allowable surveillance extension of 25 percent be applied. Attachments 1A and 1B to this letter provide new marked-up TS pages, with the appropriate frequency notations, to replace the corresponding pages submitted in Attachments 1A and 1B to Reference 4. Attachments 2A and 2B provide new TS pages, with the changes incorporated, to replace the corresponding pages submitted in Attachments 2A and 2B to Reference 4. Attachment 3 identifies the commitment made in this letter.

The information provided in this letter consists of supporting information for the amendment request previously submitted by Reference 1 and supplemented by Reference 4. The information in this letter does not alter the validity of the original evaluation of significant hazards considerations performed in accordance with 10 CFR 50.92 documented in Enclosure 2 to Reference 1. The environmental assessment provided in Enclosure 2 to Reference 1 also remains valid.

Should you have any questions, please contact Mr. Brian A. McIntyre, Manager of Regulatory Affairs, at (269) 697-5806.

Sincerely,

A. C. Bakken III
Senior Vice President, Nuclear Operations

KAS/rdw

Enclosures:

1. Affirmation
2. Response to Nuclear Regulatory Commission Request for Additional Information

Attachments:

1A and 1B. Technical Specification Pages Marked to Show the Proposed Changes
2A and 2B. Technical Specification Pages with the Proposed Changes Incorporated
3. Regulatory Commitments

c: H. K. Chernoff, NRC Washington, DC
K. D. Curry, Ft. Wayne AEP
J. E. Dyer, NRC Region III
J. T. King, MPSC
MDEQ - DW & RPD
NRC Resident Inspector
J. F. Stang, Jr., NRC Washington, DC

AFFIRMATION

I, A. Christopher Bakken III, being duly sworn, state that I am Senior Vice President, Nuclear Operations of American Electric Power Service Corporation and Vice President of Indiana Michigan Power Company (I&M), that I am authorized to sign and file this request with the Nuclear Regulatory Commission on behalf of I&M, and that the statements made and the matters set forth herein pertaining to I&M are true and correct to the best of my knowledge, information, and belief.

American Electric Power Service Corporation

A. C. Bakken III
Senior Vice President, Nuclear Operations

SWORN TO AND SUBSCRIBED BEFORE ME

THIS 7th DAY OF April, 2003

Julie E. Newmiller
Notary Public

My Commission Expires 8-22-2004

JULIE E. NEWMILLER
Notary Public, Berrien County, MI
My Commission Expires Aug 22, 2004

RESPONSE TO NUCLEAR REGULATORY COMMISSION REQUEST FOR ADDITIONAL INFORMATION REGARDING EXTENSIONS OF SURVEILLANCE TEST INTERVALS

This attachment provides Indiana Michigan Power Company's (I&M) response to the Nuclear Regulatory Commission (NRC) request for additional information (RAI) transmitted by Reference 1.

NRC Question 1

NUREG-1431, Rev. 2, "Standard Technical Specifications Westinghouse Plants," includes specific requirements for MASTER and SLAVE relay testing which are incorporated into the analysis of WCAP-15376. Technical justification needs to provide the basis for not including these testing requirements as defined in the NUREG-1431. This justification should address, but not be limited to, frequency of testing, expected duration of testing, and technical details of the type of testing performed. In the August 30, 2002, submittal, Attachment 3, Table 3.1, Note 12 states, "The master and slave relays at CNP do not have TS requirements." Explain the basis and technical acceptability of this statement.

I&M Response to NRC Question 1

The content of the current technical specifications (TS) for Donald C. Cook Nuclear Plant (CNP) was established at the time of their issuance, March 30, 1976 and December 23, 1977, for Units 1 and 2, respectively. CNP Unit 1 was the first plant to adopt the Standard Technical Specifications, and the TS for both Units 1 and 2 were generally consistent with content and format requirements of NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors." Over the past 25 years, the CNP TS have been modified by approved amendments. In contrast to the improved standard technical specifications (ISTS) presented in NUREG-1431, Revision 2, "Standard Technical Specifications Westinghouse Plants," the CNP TS do not include explicit requirements to perform functional testing of the master and slave relays used in the reactor trip system (RTS) and engineered safety features actuation system (ESFAS). However, periodic testing of master and slave relays is procedurally required at CNP to verify system operability, as defined in TS 1.6, "OPERABLE – OPERABILITY."

Master relays are considered part of the engineered safety features (ESF) automatic actuation logic (e.g., ESFAS Functional Units 1.b, 2.b, 3.a.2, 3.b.2, 4.b, and 10.b) and are tested as part of the solid-state protection system (SSPS) automatic trip/actuation logic functional tests. TS Table 4.3-2 currently requires channel functional tests of the automatic actuation logic to be performed on a monthly frequency, with each train or logic channel being tested at least every other 31 days. To test the master relays, the relays are energized and continuity is verified through the associated slave relay coils (at reduced voltage to prevent ESF actuation) with the master relay contacts. Operability of the master and slave relays is indicated by illumination of the appropriate combination of test lamps, which indicates the master relay has changed state appropriately, and the associated slave relays have satisfied the electrical continuity requirements. The time required for the master relay testing portion is generally less than 30 minutes.

Slave relays are considered part of the ESF equipment and are tested as part of the ESF electrical equipment surveillance testing. The TS testing frequency for ESF electrical equipment is on an 18-month refueling cycle. The primary method of testing is to generate an actuation signal for a train, thereby energizing the associated slave relays. Verification of the operability of the slave relays is indicated by actuation of the associated ESF equipment. Due to the various types of testing requirements for ESF electrical equipment, some surveillances would require testing to verify slave relay contact continuity change, while sequential overlapping testing would verify the operability of all the circuits up to, and including, the final device. One example where slave relay testing is performed is in the emergency diesel generator load sequencing and ESF testing, which satisfies the surveillance requirements of TS 4.8.1.1.2.c.6.b. CNP's current slave relay testing protocol exceeds that specified in the NUREG-1431 definition of slave relay tests, in that the ESF OPERABILITY is based on the successful actuation of the testable actuation devices, rather than a continuity check of these devices. Since slave relays are tested as part of the ESF equipment, testing of all slave relays is not performed at one time, and the duration of the tests varies (e.g., completion of the EDG load sequencing and ESF testing can take over a day to complete).

Notwithstanding the above, it should be noted that slave relay testing, as defined in NUREG-1431, Revision 2, is not affected by the changes evaluated by WCAP-15376-P-A, TSTF-411, Revision 1, or I&M's proposed license amendment. In fact, WCAP-15376-P-A, Section 1.0, specifically states, "Extension of the STIs for slave relays are not included in this assessment, since they were previously addressed in other WOG programs." Based on the testing performed as described above, I&M meets the master and slave relay testing operability requirements. TS surveillance requirements for master and slave relays will be adopted with CNP's conversion to ISTS.

NRC Question 2

Confirmation is required to show that the reactor protection system (RPS) site reliability data has been evaluated / reviewed ensuring conformity with WCAP-15376 and NUREG/CR-5500, "Reliability Study: Westinghouse Reactor Protection System, 1984-1995," Volume 2, April 1999.

I&M Response to NRC Question 2

WCAP-15376-P, Section 8.3.5 states that, "The values for the parameters used in this study are based on NUREG/CR-5500, whereas the values used in WCAP-14333 are conservative generic values." The CNP Probabilistic Risk Assessment (PRA) model also uses RPS failure probability values from NUREG/CR-5500, Volume 2. These values are generic in nature and determined for the Westinghouse Analog 7300 Series RPS design.

NRC Question 3

The proposed changes to TS Table 4.3-1 functional units 21 and 23 incorporate a 4-month frequency (at least once per 124 days) for surveillance testing. A 4-month frequency is not a direct replacement for 62 days on a STAGGERED TEST BASIS. Application of the provisions of TS 4.0.2, which permits a 25 percent extension of surveillance intervals to the 4-month frequency results in a 31 day allowed surveillance extension. Application of TS 4.0.2 to the 62 days on a STAGGERED TEST BASIS term results in a 15.5 day allowed surveillance extension. This difference from NUREG-1431, Rev. 2, "Standard Technical Specifications Westinghouse Plants," and TSTF-411, "Surveillance Test Interval Extensions for Components of the Reactor Protection System (WCAP-15376)," Revision 1, should be explained and technically justified.

I&M Response to NRC Question 3

In Reference 2, I&M proposed adding notations to TS Tables 4.3-1 to specify staggered testing for the reactor trip breakers (RTBs) and reactor trip bypass breakers (RTBBs). The surveillance interval proposed by notation (5) to TS Table 4.3-1 is in agreement with the interval for testing each train of RTBs and RTBBs, as evaluated by WCAP-15376-P. However, I&M concurs with the NRC staff's assertion that the proposed 4-month frequency for RTS Functional Units 21.A, 21.B, and 23 would allow a longer surveillance interval than evaluated by WCAP-15376-P should the provisions of 4.0.2 be applied. I&M has provided revised TS pages in Attachments 1A, 1B, 2A, and 2B to this letter that resolve this inconsistency.

NRC Question 4

The proposed changes to TS Table 4.3-1 functional units 19 and 22 and Table 4.3-2 functional units 1, 2, 3, 4, 6, and 10 incorporate an SA (at least once per 184 days) frequency for surveillance testing. An SA frequency is not a direct replacement for 92 days on a STAGGERED TEST BASIS. Application of the provisions of TS 4.0.2 to the SA frequency results in a 46 day allowed surveillance extension. Application of TS 4.0.2 to the 92 days on a STAGGERED TEST BASIS term results in a 23 day allowed surveillance extension. This difference from NUREG-1431, Rev. 2, and TSTF-411, should be explained and technically justified.

I&M Response to NRC Question 4

In Reference 2, I&M proposed adding notations to TS Tables 4.3-1 and 4.3-2 to specify staggered testing for various Reactor Trip System (RTS) and Engineered Safety Feature Actuation System (ESFAS) functional units. The surveillance intervals proposed by notation (15) to TS Table 4.3-1 and notation (2) to TS Table 4.3-2 are in agreement with the intervals for testing each train, as evaluated by WCAP-15376-P. However, I&M concurs with the NRC staff's assertion that the proposed semi-annual frequency for RTS Functional Units 19 and 22 and ESFAS Functional Units 1.b, 2.b, 3.a.2), 3.b.3), 4.b, 6.c, and 10.b would allow a longer surveillance interval than evaluated by WCAP-15376-P should the provisions of 4.0.2 be applied. I&M has provided revised TS pages in Attachments 1A, 1B, 2A, and 2B to this letter that resolve this inconsistency.

NRC Question 5

In the August 30, 2002, submittal, Attachment 3, Table 3.2, some of the "Agree" entries in the column titled, "CNP Plant-specific Parameter," are marked with a superscript "**" footnote. The footnote states, "Events without automatic protection are addressed by procedure, which directs a reactor trip when required to maintain plant control or safety margins." It is unclear how this footnote affects the meaning of the, "CNP Plant-specific Parameter," column entries. Confirmation is needed that the signal actuation source for each event in the table conforms to the WCAP-15376 analyses assumptions.

I&M Response to NRC Question 5

CNP design and operation is applicable to the generic Westinghouse nuclear plant, as evaluated in WCAP-15376-P, for the footnoted events. The Reference 2, Table 3.2 footnote is annotated on the following events: loss of condenser, loss of instrument air, inadvertent opening of a steam valve, and loss of service water or component cooling water. These events do not have automatic reactor protection as a direct result of the event, as is the case for the other events in Table 3.2, but rely on indirect reactor protection. For example, CNP does not have automatic protection directly from instrumentation identifying a loss of condenser, although diverse reactor protection is available due to a turbine trip (above the P-7 interlock) or steam generator water level-low-low signal resulting from feedwater pump trip. In addition, plant procedures provide direction to operators to respond, including tripping the reactor to maintain plant control or safety margins. The intent of the footnote is to state that while these events do not have direct reactor protection, procedures direct operators when to initiate a reactor trip, in addition to relying on any indirect diverse/nondiverse signals that would automatically trip the reactor. Each event annotated as "agreed" in Table 3.2 of Reference 2 conforms to the analyses assumptions in WCAP-15376-P.

NRC Question 6

Reference needs to be provided to plant procedures that require timely completion of common cause evaluations for failures of RPS channels with extended testing frequencies and additional testing for plausible common cause failures. The wording on page 8 of Enclosure 2 to the August 30, 2002, does not explicitly identify procedures that require this action.

I&M Response to NRC Question 6

I&M's Surveillance Test Program procedures specify that failure to satisfy the acceptance criteria of an RTS/ESFAS Channel Functional Test will require immediate notification of the Shift Manager (SM) or Unit Supervisor (US) and initiation of a condition report identifying the failure. Upon notification of a failed channel under any condition, the SM or US would query the I&C technician to determine the nature of failure and the extent of condition associated with the failure. While not specifically required by procedure, the SM or US would typically require evaluation and inspection of the other channels, including the opposite unit, if the failure is indicative of a plausible common cause that could affect other channels. However, to satisfy the condition stipulated in the February 21, 1985 Safety Evaluation Report for WCAP-10271 (Reference 5), I&M will implement procedures to consider potential common cause for equipment failures and to initiate testing/inspection if necessary. These procedural requirements will be in place prior to implementation of the proposed revisions to the TS.

NRC Question 7

The discussion on pages 8-9 of Enclosure 2 to the August 30, 2002, submittal states that, "Only those instrument channels that have hardware installed to permit testing in bypass without using lifting leads or installing jumpers are routinely tested in bypass." This statement does not definitively prohibit surveillance testing in bypass for instrument channels that do not have hardware installed to permit testing in bypass without lifting leads or installing jumpers. The Safety Evaluation Report (SER) for WCAP-10271-P-A, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," states that, "Testing of the RTS analog channels in the bypassed condition[s] by use of temporary jumpers or lifting leads is not acceptable." Clarification of conformance with this implementation requirement is needed.

I&M Response to NRC Question 7

I&M performs testing of the RTS and ESFAS analog channels in accordance with approved surveillance test procedures. CNP's Instrumentation and Controls surveillance test procedures do not specify a process for testing channels in bypass through the use of lifting leads or jumpering channels.

NRC Question 8

The SERs for WCAP-10271-P-A, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP-10271-P-A, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," require that any increase in instrument drift due to extended surveillance test intervals (STIs) be properly accounted for in the setpoint calculation methodology. Additional guidance was provided in a letter dated April 27, 1988, C. Rossi, NRC, to R. Janecek, BWR Owners' Group. This guidance document states that, "...licensees need only to confirm that the setpoint drift which could be expected under the extended STIs has been studied and either 1) has been shown to remain within the existing allowance in the RPS and engineered safety features actuation system (ESFAS) instrument setpoint calculation, or 2) the allowance and setpoint have been adjusted to account for the additional expected drift." Discussion on page 15 of the August 30, 2002, submittal states that for the Foxboro Spec 200 components in the RTS and ESFAS, a study has confirmed that the one percent rack drift assumption used in the current setpoint methodology bounds the manufacturers drift specification and is consistent with field data. This does not appear to directly address the evaluation of expected behavior for extended STIs. Similarly, the discussion of the remainder of the affected instrumentation does not directly address the established acceptance criteria from the April 27, 1988, guidance letter. In fact, a qualitative assessment is discussed. Confirmation should be provided that any increase in instrument drift due to extended STIs has been, or will be, properly accounted for in the setpoint calculation methodology.

I&M Response to NRC Question 8

The two-part study I&M summarized in Reference 2 concluded that an adjustment of the setpoint calculation methodology is not required for the RTS and ESFAS instrumentation due to extended surveillance test intervals. I&M's methodology incorporates the actual periodicity associated with each particular function to determine drift.

The first part of the study reviewed the Foxboro Spec 200 MICRO components in the RTS and ESFAS analog channels. The Foxboro Spec 200 MICRO components convert the analog field signal to digital. This study encompassed the analog channels listed in TS Tables 4.3-1 and 4.3-2 that are subject to this request, except for the nuclear instrumentation channels. The study determined that the manufacturer's one-year drift specifications are bounded by the one percent rack drift assumption used in the setpoint calculation methodology. An evaluation of representative field data determined that the field data is consistent with the manufacturer's drift specifications. Based on the above, an extension of the surveillance periodicity would still be bounded by the existing drift assumption and methodology.

The second part of the study reviewed the power range nuclear instrumentation. This part of the study was based, in part, on approximately 21 months of monthly channel functional test (CFT) data and quarterly channel calibration data. The review of the monthly and quarterly surveillance data found no instances where either the neutron flux high or low bistable setpoints, neutron flux high positive rate bistable setpoint, or neutron flux high negative rate bistable setpoint had drifted beyond the allowed tolerance value. All of these neutron flux trips use the same bistable model. Based on the above, it is expected that an extension of the surveillance periodicity would still be bounded by the existing drift assumption and the methodology.

The power range nuclear instrumentation calibration method uses front panel-mounted analog test meters and indication lights as the testing instrumentation. This type of testing does not have adequate precision for rigorous rack drift analysis, however, the tolerances applied in the field calibration methodologies are much smaller than allowed in the setpoint methodology. Controls exist to ensure these tight as-left and as-found tolerances are maintained.

The CNP Critical Parameter process requires that each out-of-tolerance occurrence be entered into the corrective action program and reviewed by the system engineer. If a particular function is found to be outside its tolerance on two consecutive occurrences, the evaluator is directed to take corrective action. This corrective action may involve, for example, bistable replacement or reanalysis of the tolerance value. Because controls exist to maintain tight tolerances, and corrective action is taken on instrumentation for repeated out-of-tolerance occurrences, a qualitative assessment of drift adequately predicts how an instrument will react following implementation of the surveillance test interval extensions. Consequently, I&M has concluded that an adjustment of the setpoint calculation methodology is not required for the RTS and ESFAS instrumentation due to the proposed extended surveillance test intervals.

NRC Question 9

NRC Inspection Report 50-315/99032(DRS); 50-315/99032(DRS) dated February 4, 2000, closed Manual Chapter 0350 Restart Case Specific Checklist Item No. 3C, "Failure to Consider Instrument Uncertainties, Setpoints, and/or Instrument Bias," and Confirmatory Action Letter Item No. 9, "Instrument Uncertainties Incorporated into Procedures and Analyses." In both cases, a conclusion was documented that sufficient evidence of completed work and/or corrective actions had established a basis for closing these items, while recognizing additional work and/or corrective actions would be completed. Confirmation of the completion of work and/or corrective actions associated with these two items should be provided.

I&M Response to NRC Question 9

Inspection Report 99032 closed Manual Chapter 0350 Restart Case Specific Checklist Item No. 3C, "Failure to Consider Instrument Uncertainties, Setpoints, and/or Instrument Bias," and Confirmatory Action Letter Item No. 9, "Instrument Uncertainties Incorporated into Procedures and Analyses" stating that additional licensee actions were required prior to restart of the units. These actions were to review procedures to incorporate instrument uncertainty and complete instrument uncertainty calculations as part of an expanded instrument uncertainty program. This expanded program included an NRC commitment made by I&M in Reference 4. Closure of this commitment was completed on March 31, 2000 after implementation of an Instrumentation and Controls Program procedure, approval of an engineering control package for Emergency Operating Procedure bases, development of a Critical Parameters List procedure, review of plant procedures requiring instrument uncertainty, and completion of required instrument uncertainty calculations.

NRC Question 10

In the August 30, 2002 submittal, Note 5 to Table 3.1 of Attachment 3 states that, "Because 'infrequent' slave relay failures are the norm at CNP, the WCAP-15376 analysis is applicable to CNP." This conclusion does not appear to be fully explained or supported. A technical basis for this conclusion needs to be provided.

I&M Response to NRC Question 10

Table 3.1 of Attachment 3 of the August 30, 2002 submittal was provided as a means of summarizing I&M's approach to demonstrating that the WCAP-15376-P analyses are applicable to CNP. For the typical at-power maintenance interval parameters, if the CNP plant-specific value for each parameter indicated that the WCAP-15376-P analyses were applicable, I&M did not attempt to quantify the degree of applicability or address the basis for the value. However, in response to the NRC staff's question pertaining to the frequency of at-power maintenance intervals for slave relays, I&M performed a review of historical slave relay failures at CNP since 1995. Based on a search of the applicable plant databases, it was concluded that no slave relay failures have occurred during this time period. Therefore, it is appropriate to characterize CNP's typical at-power maintenance intervals for slave relays as "infrequent," in support of the conclusion that the WCAP-15376-P analyses are applicable to CNP.

NRC Question 11

In the August 30, 2002, submittal it is noted in Attachment 3, page 13 that the probabilistic risk assessment (PRA) Peer Review recommended that, "Common cause screening could be improved, and plant-specific common cause screening should be considered." How do these statements affect the WCAP-10271 SER requirements concerning treatment and identification of common cause failures? The basis for the conclusion that the Level A and Level B Facts and Observations from the PRA Peer Review are, "not relevant," should also be provided. Additionally, the schedule for the resolution of the PRA Peer Review Level A and Level B Facts and Observations should be provided.

I&M Response to NRC Question 11

Treatment and Identification of Common Cause Screening

The WCAP-10271 SER (Reference 5) made the following statements regarding common cause failures (CCFs).

> In order to validate the staff's underlying assumption, the staff's acceptance of less frequent surveillance is contingent on implementation of procedures to identify common cause failures and to test the other channels which may be affected by the common cause. [Page 8]
>
> The approval of Item 1 is contingent on performance of the testing on a staggered test basis and implementation of procedures to evaluate failures for common cause and perform additional testing if necessary. These contingencies will minimize the risk of common cause failures. [Page 10]

The above statements refer specifically to the actions that should be taken as part of the troubleshooting effort that occurs in the aftermath of a RPS component failure. Implementation of this type of procedure is effectively a risk management action that should minimize the possibility of suffering a CCF due to some failure mechanism that has occurred. However, the procedural requirement for evaluation of CCFs, as addressed in the WCAP-10271 SER, has no other connection to the PRA model or the common cause modeling techniques that are the subject of the PRA Peer Review recommendation.

There was one principal CCF fact and observation (F&O) of concern to the PRA peer reviewers. This issue was associated with the methodology used to calculate the Multiple-Greek-Letter (MGL) factors applied to the component failure rates. This F&O criticized the use of MGL values derived from generic data that included causes which did not apply to CNP. The original basis for using such data was provided in the Westinghouse CCF guidance that was adopted by I&M during the performance of the Individual Plant Examination (IPE). This guidance stated that the generic MGL parameters should be used as screening values until a CCF basic event was determined to dominate the core damage frequency (CDF). In such a case, the guideline recommended that the more detailed (and hence more time-consuming) plant-specific screening of CCF data should be performed. Moreover, prior to the PRA update performed in 2001, no CCF terms were considered to dominate CNP's CDF. However, the dominant CDF sequence determined by the 2001 update of the CNP PRA model does involve a CCF event in the essential service water system. The need to re-visit this CCF event was not recognized until the Peer Review comment was received.

The concern identified in the F&O does not directly relate to the RTS/ESFAS model in the CNP PRA (referred to as RPS/ESFAS in the model documentation). Although the RTS/ESFAS model consists of modules developed at a system/train level, the CCF for the signals are explicitly included in each module. None of these CCF events is included in a dominant CDF or large early release frequency (LERF) sequence. Accordingly, by CNP's governing guidance documents, additional plant-specific development of these CCF terms is not warranted. From a more practical point of view, the RTS/ESFAS components and design are of a similar type to those in industry, and the systems are maintained in a similar configuration (i.e., standby). In addition, there is much more standardization of the RTS/ESFAS systems among Westinghouse plants than there is for service water systems. This is because the original RTS/ESFAS system/equipment vendor is the same for all of these plants, while the service water systems reflect differences in design philosophies between the various plants' architectural/engineering firms. Based on the above, it is less likely that a plant-specific screening of CCF events for RTS/ESFAS would result in a significantly different result than obtained generically. Therefore there is little or no impact from this F&O on the results presented for the RTS/ESFAS TS changes.

F&O's on CNP PRA Model

The Westinghouse Owner's Group (WOG) Peer Review of the CNP PRA model provided three Level A and 24 Level B F&Os. Preliminary changes to the PRA model have been made to address two of the level A and all 24 of the Level B F&Os. Although the technical review of the modeling changes is still underway to verify that these F&Os have been resolved completely, there is reasonable assurance that the modeling changes are accurate. The impacts of the changes to the PRA model were reviewed, and they were insignificant with respect to the RTS/ESFAS models. Therefore, the PRA results and conclusions presented in References 2 and 3 remain valid. Final acceptance of the revised PRA model that addresses the Level A and B findings, excluding the single Level A finding associated with internal flooding, is scheduled to be completed by the end of October 2003. Once final acceptance of the model is complete, the revised model will become the Model of Record that is used for future PRA-related analyses.

With respect to the single Level A finding that is not resolved, the reviewers identified several weaknesses in the current flooding analysis and suggested that an updated flooding analysis be performed. Since this was a major finding for a large number of plants, industry efforts are also underway to develop an industry standard for evaluating internal flooding impacts. The timing for completion of the flooding analysis to resolve this F&O is dependent upon the finalization of an industry standard.

Although the influence on the PRA results from revising the flooding analysis cannot be specifically quantified at this time, the effects of extending the RTS/ESFAS surveillance test intervals, completion times, and bypass times on flooding can be qualitatively assessed. Since the screening criteria used in the current flooding analysis did address pipe spray, potential spurious actuation of RTS/ESFAS circuitry due to pipe spray has been evaluated and eliminated. Maintenance on the RTS/ESFAS circuitry cannot cause flooding of other vital equipment.

Therefore, this F&O is judged to have an insignificant affect on the results for the proposed RTS/ESFAS TS changes.

NRC Question 12

On page 3 of Attachment 3 to letter dated February 27, 2003, a ratio-based comparison of CNP LERF/CDF and WCAP-15376 LERF/CDF values is provided. The CNP values result in 11.5 percent of CDF sequences progressing to LERF. For WCAP-15376, 4.7 percent of CDF sequences progress to LERF. An attempt is then made to establish an estimate of the CNP specific increase in LERF for the proposed changes by applying the CNP derived ratio of 11.5 percent to the WCAP-15376 deterministically established values for CDF for 2/4 and 2/3 logic. The technical and regulatory bases should be provided for either: 1) the similarity of the CNP PRA model to the WCAP-15376 model, such that direct comparisons are technically valid, or 2) technical evaluation of the CNP cutsets proving that the ratio of CDF sequences that lead to LERF would not be affected by the proposed completion time and surveillance extensions of WCAP-15376 for each piece of equipment. The response to this question should encompass the application of this LERF/CDF ratio in the response to NRC Condition and Limitation 3 on page 5 of Attachment 3 to letter dated February 27, 2003.

I&M Response to NRC Question 12

CNP PRA Model Comparison to WCAP-15376 PRA Model

WCAP-15376-P, Section 8.1.2 identifies the key characteristics associated with the PRA model used in the analysis. A comparison of these key characteristics to the characteristics of the CNP PRA model has been performed to ensure that the similarity between the CNP PRA model and the model used to support WCAP-15376-P are sufficient to ensure that direct comparisons are technically valid. The key characteristics of the WCAP-15376-P model and a discussion of how the CNP model compares to the characteristics is provided below.

WCAP-15376-P Model Key Characteristics

- ESFAS must be incorporated into the model in sufficient detail to reflect the actuation signal/actuated system interface. Signals are required for actuation of engineered safety features such as emergency core cooling system, auxiliary feedwater pump start, main steamline isolation, containment spray, and containment isolation.
- The PRA model must allow for crediting operator actions to actuate the safety systems if the automatic signals fail. The model must also be able to account for dependencies of subsequent operator actions in previous operator actions.
- The plant needs to have available procedures that direct the plant operators to initiate safety systems if automatic actuation fails.

- The PRA model must address anticipated transient without scram (ATWS) events (failure of the reactor trip signal).
- The plant needs to have available procedures that direct the operators to trip the plant and respond to an ATWS event if the automatic actuation fails.
- An inclusive set of initiating events along with detailed plant response (event) trees are required.
- Consistency in the level of modeling detail between the actuation system and actuated systems and components is necessary.
- PRA model quality and completeness (with regard to the RPS signals to trip the reactor and initiate safety systems) is important.

CNP Model Comparison

The CNP PRA model uses a support system approach and examines a full complement of internal events. It includes a thorough examination of the signals required to actuate the safety features of the plant, including reactor trip and ESFAS. ESF acutation signals for safety injection (SI) are modeled in the support system fault trees. Appropriate actuation signals are included, as necessary, in the model for containment spray actuation, containment isolation, auxiliary feedwater pump start, main steam system isolation, and emergency core cooling system actuation. Events also credit operator action, as appropriate, to initiate SI via the SI switch in the control room, or to start individual pumps and manipulate valves. Reactor trip actuation signals are included for initiating events as necessary. Operators are also given credit for manual tripping of the reactor if the automatic reactor trip actuation signals fail. The level of detail for component modeling is consistent with respect to the components that the actuation signals are required to actuate. That is, the mechanical components that require actuation by RTS/ESFAS are included in the CNP PRA model. This includes pumps that are required to start, valves that are required to change position, etc.

Although the signal unavailability models developed and evaluated in WCAP-15376-P were based on the signal unavailability models in the Vogtle PRA model, WCAP-15376-P models are not Vogtle specific, but have been determined to be applicable to all Westinghouse plants. Since the CNP PRA model meets the key characteristics identified in WCAP-15376-P as required for the representative model upon which WCAP-15376-P was based, and since the WCAP-15376-P model is a PRA model for the generic Westinghouse design that is in use at CNP, direct comparisons between the CNP model results and WCAP-15376-P are technically valid.

Technical Evaluation of LERF-to-CDF Ratio

In Reference 3, I&M used a LERF-to-CDF ratio to estimate CNP-specific LERF increases attributable to the proposed TS changes by applying the ratio to the CDF results provided in WCAP-15376-P. This LERF-to-CDF ratio could be affected indirectly via the various initiating events' CDF contributions and/or directly via a change in containment performance. Relaxed RTS/ESFAS TS surveillance intervals, allowed outage times, and bypass times could cause an increase in the relative CDF contributions of the various initiating events such that initiators with higher LERF-to-CDF ratios become more important. In addition, extended RTS/ESFAS surveillance intervals or completion/bypass times could affect containment systems' mitigation performance, and thereby increase the conditional probability that any specific core damage sequence progresses to a large, early release. The discussion that follows shows that the LERF-to-CDF ratio is approximately constant and that the conditional LERF probability given core damage is unchanged for the proposed TS changes.

The existing Cook PRA model for RTS/ESFAS is a simplified representation of that system. The level of detail included in the model was judged to be adequate to identify any plant-specific vulnerability, which was the purpose of an IPE model. The Peer Review of the CNP model did not identify that any additional modeling of the RTS/ESFAS system was required for use of the model in applications. The notebook that addresses the basis for the PRA modeling of the RTS and ESFAS describes the genesis and conservative nature of the CNP RTS/ESFAS PRA model as follows:

> This system notebook presents the fault tree modules and values for application in the Donald C. Cook Nuclear Plant fault trees requiring reactor trip or ESF actuation. The modules were developed as part of the Cook Nuclear Plant Probabilistic Risk Assessment (PRA), and will make use of signal unavailability values quantified for V. C. Summer.
>
> ... the Summer values are conservative due to differences in the required actuation logic between Summer and Cook Nuclear Plant. It takes fewer analog channel failures to cause signal failure at Summer than it does at Cook Nuclear Plant, and the unavailabilities of the logic implementations are not significantly different. Therefore, the Summer unavailabilities are higher.
>
> ...The unavailability of ESFAS will be conservatively estimated by a single value quantified for the V. C. Summer, Solid State Protection System. ....
>
> Safety injection on Pressurizer Pressure Low 2/3 was quantified because it may be the only signal to detect a small loss of coolant accident during the critical period. The unavailability of this signal will be conservative with respect to accidents where diversity of actuation can be assumed. This unavailability can also be conservatively applied to components that require other actuation signals (e.g., Steam Generator Water Level Low Low, RCP Undervoltage, and Containment Pressure Hi Hi) because of the difference in the required logic, and the small contribution of the individual analog channels.

These excerpts from the system notebook make clear that there is conservatism built into the CNP RTS/ESFAS PRA model. For this application, conservative means that the assumed failure probabilities are higher than a more detailed model would predict. Such higher failure probabilities for the RTS/ESFAS cause higher frequencies for core damage and large early release sequences whose progressions are aided by RTS/ESFAS failures.

A detailed comparison was made between the RTS/ESFAS signal unavailabilities determined in WCAP-15376-P and the RTS/ESFAS signal unavailabilities used in the CNP PRA model. The CNP PRA model represents the unavailability for signals causing SSPS SI by seventeen distinct modules, the unavailability for signals causing SSPS Auxiliary Feedwater Pump Start by twelve distinct modules, and the unavailability for signals causing Reactor Trip by one basic event.

The Cook PRA model was quantified with changes to assure that each contribution to each module is at least approximately equal to or greater than their corresponding values in WCAP-15376-P. These changes (i.e., random failures, tests and maintenance, common cause failure of the required power supplies, and common cause failure of the signals) also cause the resulting overall unavailability for many of the modules to be significantly larger than their corresponding WCAP-15376-P value. The results of this case are an increase in CDF from 4.848E-05 to 5.328E-05 (+9.90 percent) and an increase in LERF from 5.588E-06 to 6.172E-06 (+10.5 percent). The LERF-to-CDF ratio for these revised values is changed from the base model ratio of 11.53 percent to 11.58 percent. Given the significant conservatism included in this sensitivity study, the LERF-to-CDF ratio may be concluded to be effectively unchanged for this case relative to the base model.

Other possible effects of increased RTS/ESFAS signal unavailability could be increased LERF due to the potentially larger probability of an unisolated containment or increased unavailability of containment systems that are credited, and mitigate large early releases. Both of these possibilities are considered further below.

In the CNP PRA model, LERF is determined by multiplying each CDF sequence by a sequence-specific factor. This factor is effectively a conditional probability that a specific core damage sequence progresses to a large, early release. The specific factor was determined based on the LERF modeling approach in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," January 1999, and the sequence-specific characteristics that modeling approach considers influential. Specifically, the CNP LERF model determines the conditional LERF probability based on the state of the hydrogen igniters (i.e., whether or not the igniters are operating), the magnitude of reactor coolant system pressure, and the state of auxiliary feedwater (AFW). The CNP LERF model does not consider the state of the containment spray system (CTS), and consequently does not credit any benefit of containment spray operation in determining the conditional probability that a CDF sequence progresses to LERF. As a result, the proposed TS changes to RTS/ESFAS for signals that actuate CTS cannot change any of the conditional LERF probabilities in the CNP PRA model.

The other aspect of potential LERF impact is that higher containment isolation signal unavailabilities might cause an increase in the probability that the containment is not isolated at the beginning of a core damage sequence. In the CNP LERF model, the containment isolation failure probability is "OR"ed with (i.e., added to) the conditional LERF probability for each sequence. Consequently, such an occurrence would increase the probability of containment isolation failure included in the conditional LERF probability, and thereby increase the LERF-to-CDF ratio. To assess this possibility, a revised containment isolation model was reviewed. This version of the containment isolation model was revised to address an F&O from the WOG Certification of the Updated PRA model. The result of this revised containment isolation model is an overall containment isolation failure probability of about 5.094E-03 at a truncation limit of 1E-10. The review of these model results confirmed that no ESFAS signal failure is contained in any of the cutsets that are obtained using this model. It is acknowledged that the proposed TS changes in RTS/ESFAS could result in ESFAS signal failures showing up in containment isolation cutsets. However, it is judged that these proposed changes are relatively minor and would not cause any cutsets to increase by the four orders of magnitude required to affect any of the significant figures in the containment isolation failure probability cited above.

Based on the sensitivity analyses described above, the use of the LERF-to-CDF ratio of 11.5 percent is appropriate, and is reflective of the potential increase in LERF due to implementation of the proposed RTS/ESFAS TS changes.

NRC Question 13

Recognizing the reliance on the technical work originally performed in support of WCAPs-10271, -14333, a discussion of potential cumulative risk impacts, if any, from implementation of WCAP-15376 proposed TS changes, should be provided.

I&M Response to NRC Question 13

I&M is requesting only those TS changes evaluated by WCAP-15376-P and has not previously requested or implemented any of the changes evaluated by WCAP-10271 or WCAP-14333. Therefore, there are no cumulative risk impacts to address for this amendment request for WCAP-10271 or WCAP-14333. Cumulative effects of the surveillance test interval, bypass time, and completion time changes proposed in WCAP-15376-P were previously addressed in I&M's response to Condition and Limitation 1 in Attachment 3 to Reference 3.

NRC Question 14

On page 6 and 7 of attachment 3 to letter dated February 27, 2003, the response to NRC Condition and Limitation 4, does not appear to directly (quantitatively) address the applicability of the WCAP-15376 model assumptions. WCAP-15376, Table 8.28 provides human error probabilities for six activities. The applicability of these values needs to be quantitatively addressed.

I&M Response to NRC Question 14

The operator actions credited in the WCAP-15376-P (from Table 8.28) are listed below along with a comparison between WCAP-15376-P human error probabilities (HEPs) and CNP HEPs for convenience:

<table>
<tr><th>WCAP-15376-P Action</th><th>WCAP HEP</th><th>CNP HEP</th></tr>
<tr><td>1. Reactor trip from the main control board trip switches</td><td>0.01</td><td rowspan="3">0.06</td></tr>
<tr><td>2. Reactor trip by interrupting power from the motor-generator sets given that the operator failed to trip by the control board switches</td><td>0.5</td></tr>
<tr><td>3. Manually insert the control rods into the core given the previous operator actions to trip have failed</td><td>0.5</td></tr>
<tr><td>4. Safety injection from the main control board switches</td><td>0.01</td><td rowspan="2">Range from 0.046 to 0.003 depending upon situation and equipment</td></tr>
<tr><td>5. Safety injection by manual actuations of individual components</td><td>0.002</td></tr>
<tr><td>6. Auxiliary feedwater pump start</td><td>0.02</td><td>0.5 Screening Value</td></tr>
</table>

The operator actions in WCAP-15376-P were compared to the operator actions at CNP. The operator actions are described in detail in various plant operating procedures, including Abnormal Operating Procedures, Emergency Operating Procedures, and their associated Functional Recovery procedures. These procedures were developed in accordance with the Westinghouse Emergency Response Guidelines (ERGs) and also influence the Operations simulator training requirements. The procedures form much of the basis for, and are used extensively in, developing the HEP in the CNP PRA.

The first three WCAP-15376-P human actions are associated with the possible operator actions available to manually trip the reactor (i.e., insert the control rods) if the automatic trip function were to fail. These modeling assumptions were evaluated as a single quantity in the CNP PRA Human Reliability Analysis (HRA). The CNP-specific HEP of 0.06 is comparable to the product of the WCAP-15376-P values (0.5 * 0.5 * 0.01 = 0.0025).

The next two WCAP-15376-P human actions are associated with operator actions available to manually initiate SI equipment using either a single control panel switch, or by manual operation of each required component (primarily pumps and valves) from the control panels in the control room. Cognitive errors are included in the CNP HRA for recognizing that SI has not initiated, and execution errors are included for the actual manipulation of the main control board switches. In the CNP model, the HEPs are modeled at the component level, and include contributions from both the cognitive and execution portions of the procedures. The plant specific HEP values for manual initiation of the SI-related components vary depending upon "dependencies" identified within the procedural steps. Each of the CNP-specific HEP values (range from 0.046 to 0.003) is comparable to the WCAP-15376-P values (0.01 and 0.002).

The final WCAP-15376-P human action is associated with the capability of the operators to manually start an AFW pump following an actuation signal failure. The CNP PRA model includes a similar human action, but the HEP value used in the model is a screening value (0.5). HEP screening values are very conservative values, and are typically only used for those human actions that do not contribute significantly to risk in a plant's PRA. The decision to use a screening value for the manual start of the AFW pump is based on the relative insignificance of the AFW pumps' overall contribution to risk in the CNP PRA model.

NRC Question 15

Technical justification needs to be provided for deviations from the surveillance testing frequencies or completion times in WCAP-15376 or TSTF-411 Rev. 1. These justifications need to include a risk-based assessment of the deviation, (e.g., the proposed change to TS Table 4.3-1 functional unit 2 requests a change to a quarterly frequency rather than the accepted 184 days.).

I&M Response to NRC Question 15

Current CNP TS for RTS functional unit 2, Power Range, Neutron Flux requires a quarterly channel calibration. The TS 1.9 Channel Calibration definition specifies that the channel calibration shall include a CFT. Channel calibrations are not within the scope of WCAP-15376-P; therefore the channel calibration for this functional unit will continue to be performed on a quarterly interval along with the proposed CFT, as required by CNP TS definition. The CFT required by functional unit 2 as well as functional unit 3, Power Range, Neutron Flux, High Positive Rate, and functional unit 4, Power Range, Neutron Flux, High Negative Rate was proposed to be consistent with the required quarterly channel calibration surveillance. This will allow both the channel calibration and CFT to be performed on this instrumentation at the same time, thereby increasing human reliability of the test performers and reducing the disturbances to control room personnel. There is no net increase in risk associated with the proposed deviation for the following reasons: 1) at CNP a CFT is already required on a quarterly interval as part of the channel calibration and changing the frequency of channel calibrations is outside the scope of WCAP-15376-P; and 2) a CFT does not defeat the safety function of the equipment being tested.

References:

1. Letter from H. K. Chernoff, Nuclear Regulatory Commission, to A. C. Bakken III, Indiana Michigan Power Company, "Donald C. Cook Nuclear Plant, Units 1 and 2 - Request for Additional Information Regarding, 'License Amendment Request to Extended Reactor Trip System and Engineered Safety Features Actuation System Surveillance Time Requiremnent as Evaluated in WCAP-15376 (TAC MB6324 and MB6325)," dated March 27, 2003

2. Letter from J. E. Pollock, Indiana Michigan Power Company, to Nuclear Regulatory Commission Document Control Desk, "Donald C. Cook Nuclear Plant Units 1 and 2 Docket Nos. 50-315 and 50-316 License Amendment Request to Extend Reactor Trip System and Engineered Safety Features Actuation System Surveillance Requirements as Evaluated in WCAP-15376," AEP:NRC:2311, dated August 30, 2002

3. Letter from J. E. Pollock, Indiana Michigan Power Company, to Nuclear Regulatory Commission Document Control Desk, "Supplement to License Amendment Request to Extend Reactor Trip System and Engineered Safety Features Actuation System Surveillance Requirements as Evaluated in WCAP-15376 (TAC Nos. MB6324 and MB6325)," AEP:NRC:3311, dated February 27, 2003

4. Letter from R. P. Powers, Indiana Michigan Power Company, to Nuclear Regulatory Commission Document Control Desk, "Implementation of Expanded Instrument Uncertainty Program," AEP:NRC:1304, dated September 8, 1998

5. Letter from C. O. Thomas, Nuclear Regulatory Commission, to J. J. Sheppard, Westinghouse Owners Group, "Acceptance for Referencing of Licensing Topical Report WCAP-10271, Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation Systems," dated February 21, 1985 (NRC Safety Evaluation for WCAP-10271-P-A and WCAP-10271-P-A, Supplement 1)

ATTACHMENT 1A to AEP:NRC:3311-01

UNIT 1
TECHNICAL SPECIFICATION PAGES MARKED TO SHOW
THE PROPOSED CHANGES

REVISED PAGES
UNIT 1

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TABLE 1.2

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours
W	At least once per 7 days.
M	At least once per 31 days.
Q	At least once per 92 days.
2 Months	At least once per 62 days
SA	At least once per 184 days
R	At least once per 549 days
S/U	Prior to each reactor startup.
P	Completed prior to each release.
N.A.	Not Applicable.

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODE IN WHICH SURVEILLANCE REQUIRED
13 Loss of Flow-Two Loops	S	R(8)	N.A.	1
14. Steam Generator Water Level -- Low-Low	S	R	SA ~~M~~	1, 2
15. Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level	S	R	SA ~~M~~	1, 2
16. Undervoltage-Reactor Coolant Pumps	N.A	R	M	1
17. Underfrequency-Reactor Coolant Pumps	N.A	R	M	1
18. Turbine Trip				
A. Low Fluid Oil Pressure	N.A.	N.A.	S/U(1)	1, 2
B. Turbine Stop Valve Closure	N.A.	N.A	S/U(1)	1, 2
19. Safety Injection Input from ESF	N.A.	N A	Q ~~M~~(4)(15)	1, 2
20. Reactor Coolant Pump Breaker Position Trip	N.A	N.A.	R	N.A
21. Reactor Trip Breaker				
A. Shunt Trip Function	N.A.	N A.	2 Months ~~M~~ (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
B. Undervoltage Trip Function	N.A.	N.A.	2 Months ~~M~~ (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
22. Automatic Trip Logic	N.A	N A.	Q ~~M~~ ~~(5)~~(15)	1, 2, 3*, 4*, 5*
23. Reactor Trip Bypass Breaker	N.A.	N.A.	2 Months ~~M~~ (5)(12) and S/U(1)(13)	1, 2, 3*, 4*, 5*

TABLE 4 3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION, TURBINE TRIP, FEEDWATER ISOLATION, AND MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a Manual Initiation	See Functional Unit 9				
b Automatic Actuation Logic	N A	N A	Q ~~M~~(2)	N.A	1, 2, 3, 4
c Containment Pressure-- High	S	R	SA ~~M~~ (3)	N A	1, 2, 3
d Pressurizer Pressure--Low	S	R	SA ~~M~~	N A.	1, 2, 3
e. Differential Pressure Between Steam Lines-- High	S	R	SA ~~M~~	N A.	1, 2, 3
f Steam Line Pressure--Low	S	R	SA ~~M~~	N A	1, 2, 3
2 CONTAINMENT SPRAY					
a. Manual Initiation	See Functional Unit 9				
b Automatic Actuation Logic	N A.	N A.	Q ~~M~~ (2)	N.A	1, 2, 3, 4
c Containment Pressure-- High-High	S	R	SA ~~M~~ (3)	N.A	1, 2, 3

TABLE 4 3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
3 CONTAINMENT ISOLATION					
a Phase "A" Isolation					
1) Manual	See Functional Unit 9				
2) From Safety Injection Automatic Actuation Logic	N A	N A	Q ~~M~~ (2)	N A	1, 2, 3, 4
b. Phase "B" Isolation					
1) Manual	See Functional Unit 9				
2) Automatic Actuation Logic	N.A	N A	Q ~~M~~ (2)	N A	1, 2, 3, 4
3) Containment Pressure--High-High	S	R	SA ~~M~~ (3)	N A	1, 2, 3
c. Purge and Exhaust Isolation					
1) Manual	See Functional Unit 9				
2) Containment Radioactivity--High	S	R	Q	N A.	1, 2, 3, 4

TABLE 4 3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
4 STEAM LINE ISOLATION					
a Manual	---------- See Functional Unit 9 ----------				
b Automatic Actuation Logic	N.A	N A	Q ~~M~~ (2)	N.A	1, 2, 3,
c Containment Pressure-- High-High	S	R	SA ~~M~~ (3)	N A.	1, 2, 3
d Steam Flow in Two Steam Lines--High Coincident with T_{avg}--Low-Low	S	R	SA ~~M~~	N A.	1, 2, 3
e Steam Line Pressure-Low	S	R	SA ~~M~~	N A	1, 2, 3
5 TURBINE TRIP AND FEEDWATER ISOLATION					
a Steam Generator Water Level--High-High	S	R	SA ~~M~~	N.A	1, 2, 3
6 MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a Steam Generator Water Level--Low-Low	S	R	SA ~~M~~	N A	1, 2, 3
b. 4 kv Bus Loss of Voltage	S	R	M	N A	1, 2, 3
c Safety Injection	N A	N A	Q ~~M~~ (2)	N A	1, 2, 3
d Loss of Main Feed Pumps	N A	N A	R	N.A	1, 2

TABLE 4 3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
9. Manual					
a. Safety Injection (ECCS) Feedwater Isolation Reactor Trip (SI) Containment Isolation- Phase "A" Containment Purge and Exhaust Isolation Auxiliary Feedwater Pumps Essential Service Water System	N.A	N.A.	N.A.	R	1, 2, 3, 4
b. Containment Spray Containment Isolation- Phase "B" Containment Purge and Exhaust Isolation	N.A.	N.A.	N.A.	R	1, 2, 3, 4
c. Containment Isolation- Phase "A" Containment Purge and Exhaust Isolation	N.A.	N.A.	N.A.	R	1, 2, 3, 4
d. Steam Line Isolation	N.A.	N.A.	Q	R	1, 2, 3
e Containment Air Recirculation Fan	N.A.	N.A.	N A.	R	1, 2, 3, 4
10. CONTAINMENT AIR RECIRCULATION FAN					
a. Manual	See Functional Unit 9				
b. Automatic Actuation Logic	N.A.	N.A.	Q ~~M~~ (2)	N.A.	1, 2, 3
c. Containment Pressure - High	S	R	SA ~~M~~ (3)	N.A.	1, 2, 3

ATTACHMENT 1B to AEP:NRC:3311-01

UNIT 2
TECHNICAL SPECIFICATION PAGES MARKED TO SHOW
THE PROPOSED CHANGES

REVISED PAGES
UNIT 2

1-10
3/4 3-12
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TABLE 1.2

FREQUENCY NOTATION

NOTATION	FREQUENCY
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W	At least once per 7 days
M	At least once per 31 days
Q	At least once per 92 days
2 Months	At least once per 62 days
SA	At least once per 184 days
R	At least once per 549 days
S/U	Prior to each reactor start-up
P	Completed prior to each release
N A.	Not Applicable

TABLE 4 3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
13. Loss of Flow-Two Loops	S	R(8)	N.A.	1
14. Steam Generator Water Level -- Low-Low	S	R	SA ~~M~~	1, 2
15. Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level	S	R	SA ~~M~~	1, 2
16. Undervoltage-Reactor Coolant Pumps	N.A.	R	M	1
17. Underfrequency-Reactor Coolant Pumps	N.A.	R	M	1
18 Turbine Trip				
A. Low Fluid Oil Pressure	N.A.	N.A.	S/U(1)	1, 2
B. Turbine Stop Valve Closure	N.A.	N.A.	S/U(1)	1, 2
19. Safety Injection Input from EFS	N.A.	N.A.	Q ~~M~~(4)(15)	1, 2
20 Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	R	N.A.
21. Reactor Trip Breaker				
A. Shunt Trip Function	N.A.	N.A.	2 Months ~~M~~ (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
B. Undervoltage Trip Function	N.A.	N.A.	2 Months ~~M~~ (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
22. Automatic Trip Logic	N.A	N.A.	Q ~~M~~ ~~(5)~~(15)	1, 2, 3*, 4*, 5*
23. Reactor Trip Bypass Breaker	N.A.	N.A.	2 Months ~~M~~ (5)(12) and S/U(1)(13)	1, 2, 3*, 4*, 5*

TABLE 4.3-2
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION, TURBINE TRIP, FEEDWATER ISOLATION, AND MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a Manual Initiation	See Functional Unit 9				
b. Automatic Actuation Logic	N A	N.A.	Q ~~M~~(2)	N A	1, 2, 3, 4
c Containment Pressure -- High	S	R	SA ~~M~~ (3)	N A	1, 2, 3
d Pressurizer Pressure -- Low	S	R	SA ~~M~~	N A	1, 2, 3
e Differential Pressure Between Steam Lines -- High	S	R	SA ~~M~~	N A	1, 2, 3
f Steam Line Pressure -- Low	S	R	SA ~~M~~	N.A.	1, 2, 3
2 CONTAINMENT SPRAY					
a Manual Initiation	See Functional Unit 9				
b Automatic Actuation Logic	N.A	N A.	Q ~~M~~ (2)	N A.	1, 2, 3, 4
c Containment Pressure -- High-High	S	R	SA ~~M~~ (3)	N A	1, 2, 3
3 CONTAINMENT ISOLATION					
a Phase "A" Isolation					
1) Manual	See Functional Unit 9				
2) From Safety Injection Automatic Actuation Logic	N.A.	N A	Q ~~M~~ (2)	N A.	1, 2, 3, 4
b Phase "B" Isolation					
1) Manual	See Functional Unit 9				
2) Automatic Actuation Logic	N A	N A	Q ~~M~~ (2)	N A	1, 2, 3, 4
3) Containment Pressure-- High-High	S	R	SA ~~M~~ (3)	N A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
c. Purge and Exhaust Isolation					
1) Manual	See Functional Unit 9				
2) Containment Radioactivity -- High	S	R	Q	N.A.	1, 2, 3, 4
4. STEAM LINE ISOLATION					
a Manual	See Functional Unit 9				
b Automatic Actuation Logic	N A	N A	Q ~~M~~ (2)	N A.	1, 2, 3
c Containment Pressure -- High-High	S	R	SA ~~M~~ (3)	N A	1, 2, 3
d Steam Flow in Two Steam Lines -- High Coincident with T_{avg} -- Low-Low	S	R	SA ~~M~~	N A.	1, 2, 3
e Steam Line Pressure -- Low	S	R	SA ~~M~~	N A.	1, 2, 3
5 TURBINE TRIP AND FEEDWATER ISOLATION					
a Steam Generator Water Level -- High-High	S	R	SA ~~M~~	N A.	1, 2, 3
6 MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a Steam Generator Water Level -- Low-Low	S	R	SA ~~M~~	N A	1, 2, 3
b. 4 kV Bus Loss of Voltage	S	R	M	N A.	1, 2, 3
c. Safety Injection	N A	N.A.	Q ~~M~~ (2)	N A	1, 2, 3
d Loss of Main Feed Pumps	N.A	N.A.	R	N A	1, 2

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
7. TURBINE DRIVEN AUXILIARY FEEDWATER PUMP					
a. Steam Generator Water Level -- Low-Low	S	R	SA ~~M~~	N.A	1, 2, 3
b Reactor Coolant Pump Bus Undervoltage	N A	R	M	N A.	1, 2, 3
8. LOSS OF POWER					
a 4 kv Bus Loss of Voltage	S	R	M	N.A	1, 2, 3, 4
b 4 kv Bus Degraded Voltage	S	R	M	N A	1, 2, 3, 4
9 MANUAL					
a Safety Injection (ECCS) Feedwater Isolation Reactor Trip (SI) Containment Isolation - Phase "A" Containment Purge and Exhaust Isolation Auxiliary Feedwater Pumps Essential Service Water System	N.A.	N A.	N A.	R	1, 2, 3, 4
b Containment Spray Containment Isolation - Phase "B" Containment Purge and Exhaust Isolation	N A	N A	N A	R	1, 2, 3, 4
c. Containment Isolation - Phase "A" Containment Purge and Exhaust Isolation	N.A	N.A.	N.A.	R	1, 2, 3, 4
d Steam Line Isolation	N A	N A.	Q	R	1, 2, 3
e Containment Air Recirculation Fan	N A	N.A	N.A.	R	1, 2, 3, 4
10 CONTAINMENT AIR RECIRCULATION FAN					
a Manual	See Functional Unit 9				
b Automatic Actuation Logic	N A.	N A	Q ~~M~~ (2)	N A	1, 2, 3
c Containment Pressure -- High	S	R	SA ~~M~~ (3)	N.A	1, 2, 3

ATTACHMENT 2A to AEP:NRC:3311-01

UNIT 1
TECHNICAL SPECIFICATION PAGES WITH THE
PROPOSED CHANGES INCORPORATED

REVISED PAGES
UNIT 1

1-9
3/4 3-13
3/4 3-31
3/4 3-32
3/4 3-33
3/4 3-33b

TABLE 1.2

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days
Q	At least once per 92 days.
2 Months	At least once per 62 days
SA	At least once per 184 days.
R	At least once per 549 days.
S/U	Prior to each reactor startup.
P	Completed prior to each release.
N.A	Not Applicable.

TABLE 4 3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODE IN WHICH SURVEILLANCE REQUIRED
13 Loss of Flow-Two Loops	S	R(8)	N.A	1
14. Steam Generator Water Level -- Low-Low	S	R	SA	1, 2
15 Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level	S	R	SA	1, 2
16. Undervoltage-Reactor Coolant Pumps	N.A	R	M	1
17. Underfrequency-Reactor Coolant Pumps	N A.	R	M	1
18. Turbine Trip				
A Low Fluid Oil Pressure	N.A	N.A.	S/U(1)	1, 2
B. Turbine Stop Valve Closure	N.A.	N.A.	S/U(1)	1, 2
19. Safety Injection Input from ESF	N.A.	N.A.	Q (4)(15)	1, 2
20 Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	R	N.A.
21. Reactor Trip Breaker				
A. Shunt Trip Function	N.A.	N.A	2 Months (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
B. Undervoltage Trip Function	N A.	N.A.	2 Months (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
22. Automatic Trip Logic	N.A	N A.	Q(15)	1, 2, 3*, 4*, 5*
23. Reactor Trip Bypass Breaker	N.A.	N.A.	2 Months (5)(12) and S/U(1)(13)	1, 2, 3*, 4*, 5*

TABLE 4 3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1 SAFETY INJECTION, TURBINE TRIP, FEEDWATER ISOLATION, AND MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a. Manual Initiation	See Functional Unit 9				
b. Automatic Actuation Logic	N A	N A	Q (2)	N.A	1, 2, 3, 4
c Containment Pressure-- High	S	R	SA (3)	N.A	1, 2, 3
d. Pressurizer Pressure--Low	S	R	SA	N.A.	1, 2, 3
e Differential Pressure Between Steam Lines-- High	S	R	SA	N A.	1, 2, 3
f. Steam Line Pressure--Low	S	R	SA	N A	1, 2, 3
2. CONTAINMENT SPRAY					
a Manual Initiation	See Functional Unit 9				
b Automatic Actuation Logic	N A	N A.	Q (2)	N A	1, 2, 3, 4
c Containment Pressure-- High-High	S	R	SA (3)	N A	1, 2, 3

TABLE 4 3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
3 CONTAINMENT ISOLATION					
a. Phase "A" Isolation					
1) Manual	See Functional Unit 9				
2) From Safety Injection Automatic Actuation Logic	N.A	N A.	Q (2)	N A	1, 2, 3, 4
b Phase "B" Isolation					
1) Manual	See Functional Unit 9				
2) Automatic Actuation Logic	N A.	N A	Q (2)	N A	1, 2, 3, 4
3) Containment Pressure--High-High	S	R	SA (3)	N.A	1, 2, 3
c. Purge and Exhaust Isolation					
1) Manual	See Functional Unit 9				
2) Containment Radioactivity--High	S	R	Q	N A	1, 2, 3, 4

TABLE 4 3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
4 STEAM LINE ISOLATION					
a. Manual	---------- See Functional Unit 9 ----------				
b Automatic Actuation Logic	N A.	N.A.	Q (2)	N.A	1, 2, 3,
c. Containment Pressure-- High-High	S	R	SA (3)	N A.	1, 2, 3
d Steam Flow in Two Steam Lines--High Coincident with T_{avg}--Low-Low	S	R	SA	N A.	1, 2, 3
e. Steam Line Pressure-Low	S	R	SA	N A	1, 2, 3
5 TURBINE TRIP AND FEEDWATER ISOLATION					
a Steam Generator Water Level--High-High	S	R	SA	N A	1, 2, 3
6. MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a Steam Generator Water Level--Low-Low	S	R	SA	N A	1, 2, 3
b 4 kv Bus Loss of Voltage	S	R	M	N.A.	1, 2, 3
c Safety Injection	N A.	N A	Q (2)	N.A	1, 2, 3
d Loss of Main Feed Pumps	N A	N A	R	N A.	1, 2

TABLE 4 3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
9. Manual					
a. Safety Injection (ECCS) Feedwater Isolation Reactor Trip (SI) Containment Isolation-Phase "A" Containment Purge and Exhaust Isolation Auxiliary Feedwater Pumps Essential Service Water System	N.A.	N.A.	N.A.	R	1, 2, 3, 4
b. Containment Spray Containment Isolation-Phase "B" Containment Purge and Exhaust Isolation	N.A.	N.A.	N.A.	R	1, 2, 3, 4
c. Containment Isolation-Phase "A" Containment Purge and Exhaust Isolation	N.A.	N.A.	N.A.	R	1, 2, 3, 4
d. Steam Line Isolation	N.A.	N.A.	Q	R	1, 2, 3
e. Containment Air Recirculation Fan	N.A.	N.A.	N.A.	R	1, 2, 3, 4
10. CONTAINMENT AIR RECIRCULATION FAN					
a Manual	See Functional Unit 9				
b Automatic Actuation Logic	N.A.	N.A.	Q (2)	N.A.	1, 2, 3
c. Containment Pressure - High	S	R	SA (3)	N.A.	1, 2, 3

ATTACHMENT 2B to AEP:NRC:3311-01

UNIT 2
TECHNICAL SPECIFICATION PAGES WITH THE
PROPOSED CHANGES INCORPORATED

REVISED PAGES
UNIT 2

1-10
3/4 3-12
3/4 3-30
3/4 3-31
3/4 3-32

TABLE 1.2

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours
D	At least once per 24 hours
W	At least once per 7 days
M	At least once per 31 days
Q	At least once per 92 days
2 Months	At least once per 62 days
SA	At least once per 184 days
R	At least once per 549 days
S/U	Prior to each reactor start-up
P	Completed prior to each release
N.A.	Not Applicable

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
13. Loss of Flow-Two Loops	S	R(8)	N.A.	1
14. Steam Generator Water Level -- Low-Low	S	R	SA	1, 2
15. Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level	S	R	SA	1, 2
16. Undervoltage-Reactor Coolant Pumps	N.A.	R	M	1
17. Underfrequency-Reactor Coolant Pumps	N.A.	R	M	1
18. Turbine Trip				
A. Low Fluid Oil Pressure	N.A.	N.A.	S/U(1)	1, 2
B. Turbine Stop Valve Closure	N.A.	N.A.	S/U(1)	1, 2
19. Safety Injection Input from EFS	N.A.	N.A.	Q (4)(15)	1, 2
20. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	R	N.A.
21. Reactor Trip Breaker				
A. Shunt Trip Function	N.A.	N.A.	2 Months (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
B. Undervoltage Trip Function	N.A.	N.A.	2 Months (5)(11) and S/U(1)(11)	1, 2, 3*, 4*, 5*
22. Automatic Trip Logic	N.A	N.A.	Q (15)	1, 2, 3*, 4*, 5*
23. Reactor Trip Bypass Breaker	N A.	N.A.	2 Months (5)(12) and S/U(1)(13)	1, 2, 3*, 4*, 5*

TABLE 4.3-2
ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION, TURBINE TRIP, FEEDWATER ISOLATION, AND MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a Manual Initiation			See Functional Unit 9		
b Automatic Actuation Logic	N A	N.A.	Q (2)	N A	1, 2, 3, 4
c. Containment Pressure -- High	S	R	SA (3)	N A	1, 2, 3
d Pressurizer Pressure -- Low	S	R	SA	N A	1, 2, 3
e Differential Pressure Between Steam Lines -- High	S	R	SA	N A.	1, 2, 3
f Steam Line Pressure -- Low	S	R	SA	N A.	1, 2, 3
2. CONTAINMENT SPRAY					
a Manual Initiation			See Functional Unit 9		
b. Automatic Actuation Logic	N A	N A	Q (2)	N.A	1, 2, 3, 4
c. Containment Pressure -- High-High	S	R	SA (3)	N.A	1, 2, 3
3 CONTAINMENT ISOLATION					
a Phase "A" Isolation					
1) Manual			See Functional Unit 9		
2) From Safety Injection Automatic Actuation Logic	N A.	N A.	Q (2)	N.A.	1, 2, 3, 4
b. Phase "B" Isolation					
1) Manual			See Functional Unit 9		
2) Automatic Actuation Logic	N.A.	N.A	Q (2)	N.A	1, 2, 3, 4
3) Containment Pressure-- High-High	S	R	SA (3)	N A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
c. Purge and Exhaust Isolation					
1) Manual	See Functional Unit 9				
2) Containment Radioactivity -- High	S	R	Q	N.A	1, 2, 3, 4
4. STEAM LINE ISOLATION					
a Manual	See Functional Unit 9				
b Automatic Actuation Logic	N A	N A	Q (2)	N A	1, 2, 3
c. Containment Pressure -- High-High	S	R	SA (3)	N.A	1, 2, 3
d. Steam Flow in Two Steam Lines -- High Coincident with T_{avg} -- Low-Low	S	R	SA	N A	1, 2, 3
e Steam Line Pressure -- Low	S	R	SA	N A	1, 2, 3
5 TURBINE TRIP AND FEEDWATER ISOLATION					
a Steam Generator Water Level -- High-High	S	R	SA	N.A	1, 2, 3
6 MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS					
a Steam Generator Water Level -- Low-Low	S	R	SA	N.A	1, 2, 3
b 4 kV Bus Loss of Voltage	S	R	M	N A.	1, 2, 3
c Safety Injection	N A	N A.	Q (2)	N.A.	1, 2, 3
d Loss of Main Feed Pumps	N A	N.A	R	N A	1, 2

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
7 TURBINE DRIVEN AUXILIARY FEEDWATER PUMP					
a. Steam Generator Water Level -- Low-Low	S	R	SA	N A.	1, 2, 3
b Reactor Coolant Pump Bus Undervoltage	N A.	R	M	N A.	1, 2, 3
8 LOSS OF POWER					
a 4 kv Bus Loss of Voltage	S	R	M	N A	1, 2, 3, 4
b 4 kv Bus Degraded Voltage	S	R	M	N A	1, 2, 3, 4
9. MANUAL					
a Safety Injection (ECCS) Feedwater Isolation Reactor Trip (SI) Containment Isolation - Phase "A" Containment Purge and Exhaust Isolation Auxiliary Feedwater Pumps Essential Service Water System	N A.	N A.	N A	R	1, 2, 3, 4
b. Containment Spray Containment Isolation - Phase "B" Containment Purge and Exhaust Isolation	N A.	N A	N.A	R	1, 2, 3, 4
c. Containment Isolation - Phase "A" Containment Purge and Exhaust Isolation	N.A	N A	N.A	R	1, 2, 3, 4
d. Steam Line Isolation	N.A	N.A.	Q	R	1, 2, 3
e Containment Air Recirculation Fan	N A.	N A.	N A	R	1, 2, 3, 4
10 CONTAINMENT AIR RECIRCULATION FAN					
a. Manual	See Functional Unit 9				
b Automatic Actuation Logic	N A.	N A.	Q (2)	N A	1, 2, 3
c Containment Pressure -- High	S	R	SA (3)	N A	1, 2, 3

ATTACHMENT 3 to AEP:NRC:3311-01

REGULATORY COMMITMENTS

The following table identifies those actions committed to by Indiana Michigan Power Company (I&M) in this document. Any other actions discussed in this submittal represent intended or planned actions by I&M. They are described to the Nuclear Regulatory Commission (NRC) for NRC's information and are not regulatory commitments.

Commitment	Date
To satisfy the condition stipulated in the February 21, 1985 safety evaluation report for WCAP-10271, I&M will implement procedures to consider potential common cause for equipment failures and to initiate testing/inspection if necessary. These procedural requirements will be in place prior to implementation of the proposed revisions to the TS.	The appropriate administrative controls will be established when the surveillance test interval extensions are implemented following NRC approval.