Entergy

Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc
Entergy Nuclear Indian Point 2, LLC
P O Box 249
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January 27, 2003

Re: Indian Point Unit No. 2
Docket No. 50-247
NL-03-002

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

Subject: Response to Request for Additional Information Regarding Section 3.8.1, AC Sources Operating, of the Improved Technical Specifications (ITS) (TAC No. MB5068)

Reference:
1) Entergy letter (NL-02-016) to NRC, "License Amendment Request (LAR 02-005) Conversion to Improved Standard Technical Specifications," dated March 27, 2002
2) Entergy letter (NL-02-092) to NRC, "Supplement 1 to the Indian Point 2 License Amendment Request for Conversion to Improved Standard Technical Specifications," dated July 10, 2002
3) NUREG 1431, "Standard Technical Specifications Westinghouse Plants," Revision 2, dated April 2001
4) 10 CFR 50.36, "Technical Specifications," as amended
5) NRC letter to Entergy Nuclear Operations, Inc., "Request for Additional Information (RAI) Regarding Section 3.8.1 – AC Sources Operating – Beyond Scope Issue No. 7 (TAC No. MB5068)," dated December 31, 2002

Dear Sir:

By letter dated March 27, 2002 (Reference 1) as supplemented by letter dated July 10, 2002 (Reference 2), Entergy Nuclear Operations, Inc. (ENO) requested to amend the Indian Point 2 (IP2) Plant Operating License, Appendices A and B, "Technical Specifications." The proposed amendment converts the IP2 Current Technical Specifications (CTS) to Improved Technical Specifications (ITS) in accordance with NUREG 1431, "Standard Technical Specifications Westinghouse Plants," (Reference 3), and the Code of Federal Regulations (CFR) (Reference 4).

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The U.S. Nuclear Regulatory Commission (NRC) staff reviewing the request has determined that additional information is required to complete its review. The request for additional information is dated December 31, 2002 (Reference 5). A list of acronyms that may have been used in this submittal has been provided as Attachment 1 to this letter. Attachment 2 to this letter, "Response to Request for Additional Information Regarding Section 3.8.1 of the Improved Technical Specifications (ITS)," provides ENO's response to the subject request for additional information. The IP2 Actions described in Attachment 2 will be incorporated in a future supplement to the ITS submittal packages.

There are no commitments contained in this letter.

Should you or your staff have any questions regarding this matter, please contact the IP2 ITS Project Manager, Mr. William Blair at (914) 734-5336.

I declare under penalty of perjury that the foregoing is true and correct.

Sincerely,

Executed on 1/27/03

Fred Dacimo
Vice President – Operations
Indian Point 2

Attachments

cc: See page 3

cc:

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ATTACHMENT 1 TO NL-03-002

List of Acronyms That May Be Used In This Submittal

Entergy Nuclear Operations, Inc.
Indian Point Unit No. 2
Docket No. 50-247

<u>List of Acronyms That May Be Used In This Submittal</u>

AC	Air Conditioning or Alternating Current
AOT	Allowed Outage Time
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transient Without Scram
BIT	Boron Injection Tank
CFR	Code of Federal Regulations
CLB	Current License Basis
COLR	Core Operating Limits Report
COT	Channel Operational Test
CST	Condensate Storage Tank
CTS	Current Technical Specification
DB	Design-Basis
DBA	Design-Basis Accident
DC	Direct Current
DG	Diesel Generator
DOC	Discussion of Change (from the CTS)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safeguard Feature
FR	Federal Register
GDC	General Design Criteria
HEPA	High Efficiency Particulate Air
Hz	Hertz
IRM	Intermediate Range Monitor
ISI	Inservice Inspection
ITS	Improved (converted) Technical Specifications
JFD	Justification For Difference
kV	Kilovolt
kW	Kilowatt
LAR	Licence Amendment Request
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LOP	Loss of Power
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
NUMAC	Nclear Measurement Analysis and Control
PAM	Post-Accident Monitoring
P/T	Pressure/Temperature
QA	Quality Assurance
RAI	Request for Additional Information

RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RTP	Rated Thermal Power
SDC	Shutdown Cooling
SDM	Shutdown Margin
SE	Safety Evaluation
SER	Safety Evaluation Report
SR	Surveillance Requirement
SRM	Source Range Monitor
STS	Improved Standard Technical Specification(s), NUREG-1431, Rev. 2
SW	Service Water
TRM	Technical Requirements Manual
TS	Technical Specifications
TSTF	Technical Specifications Task Force (re: generic changes to the STS)

ATTACHMENT 2 TO NL-03-002

Response to Request for Additional Information Regarding Section 3.8.1 of the Improved Technical Specifications (ITS)

Entergy Nuclear Operations, Inc.
Indian Point Unit No. 2
Docket No. 50-247

Response to Request for Additional Information

The NRC Staff reviewing information provided in the March 27, 2002 license amendment request as supplemented by letter dated July 10, 2002 has determined that additional information is required to complete its review. The following are the specific requests from the NRC staff and ENO's response to those requests.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 1	**MB5068**

NRC Request for Additional Information (RAI):

Note to Surveillance Requirement (SR) 3.8.1.12 allows all three emergency diesel generators (EDG) to be tested concurrently, however during shutdown at least one EDG is required to be operable. Please justify testing all three EDGs simultaneously.

Entergy (IP2) Response:

IP2 ITS SR 3.8.1.12 maintains the requirement in CTS 4.6.A.2 to conduct a combined safety injection actuation signal and loss of offsite power test which demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal.

IP2 ITS 3.8.1.12 differs from STS (NUREG-1431) SR 3.8.1.19 by the addition of Note 3 which states: "This SR may be performed on safeguards power trains one at a time, or simultaneously. Appropriate plant conditions must be established when testing three safeguards power trains simultaneously."

Note 3 to ITS SR 3.8.1.12 is explained in the markup of NUREG-1431 as Bases Insert B 3.8.1 - 32 -01 which states:
"The reason for Note 3 is to allow the SR to be conducted with only one safeguards train at a time or with two or three safeguards trains concurrently. Allowing the LOOP/LOCA test to be conducted using one safeguards power train and one DG at a time is acceptable because the safeguards power trains are designed to respond to this event independently. Therefore, an individual test for each safeguards power train will provide an adequate verification of plant response to this event.

Note that a DG that is setup to perform this test will respond to a loss of offsite power (LOOP) as required. Additionally, during performance of the test, the DG is performing its safety function for a LOOP and the plant is not connected to offsite power and not vulnerable to a LOOP. Therefore, DG Operability status during this test is not a significant concern.

In addition, the Bases for ITS SR 3.8.1.12 explain the plant conditions that must be established for simultaneous testing of all three safeguards power trains. The necessary plant conditions specified in the Bases are:
a. All three DGs are available;
b. Redundant decay heat removal capability is available, preferably including passive decay heat removal capability;
c. No offsite power circuits are inoperable, and
d. No activities that are precursors to events requiring AC power for mitigation (e.g., fuel handling accident or inadvertent RCS draindown) are conducted during performance of this test."

These conditions, in particular having both offsite circuits and all three DGs available, are more restrictive than the Required Actions in LCO 3.8.2 for a condition where all three DGs are inoperable in Mode 5 or 6. Placing these conditions in the Bases was an NRC prerequisite for allowing IP3 to continue to perform simultaneous testing when IP3 converted to improved Technical Specifications.

Furthermore, IP2 believes that simultaneous testing of all three DGs during a LOOP/LOCA test is not only acceptable but is the preferred method. Significant safety benefit would result from discovering common failure resulting from interdependence among DGs and/or safeguard power trains during shutdown testing versus discovering these failure modes during an actual event. This test does not compromise safety because: a) the test can only be initiated when all DGs are Operable and there is full redundancy for all ESF systems; b) the plant is deliberately configured to tolerate the potential for a loss of all AC power prior to initiation of the test; and, c) the plant is restricted from performing any activity that is a precursor to a shutdown event that requires AC power for mitigation. IP2 also believes that an unplanned event or an adverse interaction between trains during the test is unlikely to result in damage to all three safeguards power trains such that at least one of the safeguards power trains could not be re-energized immediately from either one of the 3 DGs or one of the two circuits that connect safeguards power trains to the offsite circuits. Finally, simultaneous testing of all three DGs during a LOOP/LOCA test provides significant time savings during refueling outages.

The following details are presented to support IP2's determination that simultaneous testing of all three DGs during a LOOP/LOCA test: 1) provides significant safety benefit; and, 2) is performed in a manner that does not compromise safety.

1) IP2's position regarding the safety benefits of simultaneous DG testing are supported by Reg. Guide 1.108, Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Power Plants, Rev. 0, August 1976, which states the following in Section C.2.d: "Testing of redundant diesel generator units 'during normal plant operation' should be performed independently (nonconcurrently) to minimize common failure modes resulting from undetected interdependence among diesel generator units. However, during ... pre-operational testing and 'once a year thereafter, a test should be conducted where redundant units are started simultaneously to help identify certain common failure modes undetected in single diesel generator tests.'

Note the sections enclosed in single quotation marks. These statements indicate that the recommendation against simultaneous testing applies only 'during normal plant operation' and that 'once a year thereafter, a test should be conducted where redundant units are started simultaneously to help identify certain common failure modes undetected in single diesel generator tests.'

RG 1.108, Rev 2, changed the frequency for simultaneous test from every year to every 10 years (during a plant shutdown). IP2 believes that the extension to 10 years was intended to be a relaxation and not a restriction and the clarification (during a plant shutdown) was intended to be a restriction. Note also that the RG 1.9 does not include any prohibition against simultaneous DG testing in the description of the Combined SIAS and LOOP Tests or any other test. RG 1.9 does specify that "Design provisions should include the capability to test each emergency diesel generator unit independently of the redundant units. Test equipment should not cause a loss of independence between redundant diesel generator units or between diesel generator load groups." However, this does not prohibit simultaneous testing.

2) IP2's position is that simultaneous DG testing during a LOOP/LOCA test is performed in a manner that does not compromise safety and, therefore, within the provisions of ITS LCO 3.0.2 which allows intentionally relying on the ACTIONS for performance of Surveillances because of the following:

2.a) This test is conducted in Mode 5 or 6 when there are minimal requirements for AC sources, there is no requirement for redundant ESF systems, and manual initiation of ESF systems is permitted. However, the test can only be initiated when all DGs are Operable, all three safeguards power trains are connected to an Operable offsite source, and there is full complement of redundant ESF systems.

2.b) This test is conducted with the plant deliberately configured to tolerate the potential for a loss of all AC power prior to initiation of the test by meeting the Required Actions for LCO 3.8.2 when there is no Operable offsite circuits and no Operable DGs. This is very conservative because with the plant shutdown there is sufficient time to terminate the test and manually align and operate any AC sources and/or ESF equipment required to respond to an event. Therefore, AC sources and ESF systems are fully functional even if not technically Operable.

2.c) When this test is in progress, the plant is restricted from performing any activity that is a precursor to a shutdown event that requires AC power for mitigation (i.e., fuel handling accident or inadvertent draining of the reactor coolant system).

2.d) IP2 also believes that an unplanned event (i.e., interaction between safeguard power trains) during the test is unlikely to result in damage to all three safeguards power trains such that at least one of the safeguards power trains could not be re-energized immediately from either one of the 3 DGs or one of the two circuits that connect safeguards power trains to the offsite circuits.

Finally, IP2 and IP3 have extensive experience conducting this test on all three safeguards power trains simultaneously and has less potential for unidentified interactions than plants which never perform this test simultaneously especially when considering that the 10 year test in NUREG-1431 and RG 1.108 and RG 1.9 do not require that DG output breakers close and energize the associated busses and equipment (i.e., this test will not identify adverse interactions between safeguard power trains).

Therefore, IP2 believes that simultaneous testing of all three DGs during a LOOP/LOCA test has significant safety benefit and can be performed in a manner that does not compromise safety.

Entergy (IP2) Action:

None.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 2	**MB5068**

NRC Request for Additional Information (RAI):

Provide justification for performing SR 3.8.1.10 for 8 hours rather than 24 hours as required by NUREG-1432, Rev. 2.

Entergy (IP2) Response:

IP2 CTS 4.6 does not include any DG testing similar to the 24 hour "Endurance and Margin Test" identified in Regulatory Guide 1.9 and duplicated in STS (NUREG-1431) as SR 3.8.1.14. IP2 is voluntarily adopting a requirement to perform a DG endurance and margin test consistent with the latest industry recommendations in IEEE Standard 387-1995, IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.

The ITS Bases for ITS SR 3.8.1.10 (i.e. STS NUREG-1431, SR 3.8.1.14) provide the following explanation: "IEEE-387-1995 requires demonstration once per 24 months that the DGs can start and run continuously at full load capability for an interval of not less than 8 hours, greater than 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating (1837 kW to 1925 kW) and the remainder of the time at a load equivalent to 90% to 100% of the continuous duty rating of the DG (1750 kW).

ITS 3.8.1, DOC M.14, provides the following justification for the new requirement for endurance testing of the DGs: "This change is needed to conform to the recommendations of IEEE 387-1995 for the endurance testing of DGs and to provide greater assurance that DG endurance is consistent with the assumptions of the accident analysis. The length of the endurance run is sufficient to demonstrate proper and adequate long term operation of the DG lube oil, fuel oil, ventilation and cooling water systems. Additionally, this test is performed at a power factor equivalent to that expected during accident conditions to verify generator loading capability. Therefore, this change has no significant adverse impact on safety."

This change is identical to changes approved for IP3 in Amendment 205 in the IP3 conversion to ITS. Similar changes have been approved as part of the ITS conversion for numerous other plants where the CTS did not include DG endurance testing.

Entergy (IP2) Action:

None.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 3	**MB5068**

NRC Request for Additional Information (RAI):

LCO 3.8.1 A3 of NUREG-1431 establishes a limit on the maximum time of 6 days allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the Limiting Condition of Operation (LCO). Please provide justification for not providing this 6 day limit as required by NUREG 1431 in the proposed SRs 3.8.1.A and B.

Entergy (IP2) Response:

STS (NUREG-1431) LCO 3.8.1, Required Action A.3 (IP2 ITS A.4) for an inoperable offsite circuit, and Required Action B.4 for an inoperable DG, include a requirement that the offsite circuit and/or the DG must be restored to Operable within "6 days from discovery of failure to meet LCO." IP2 ITS did not include this 'second Completion Time' because it is not required by the CTS.

This deviation from the NUREG is explained and justified in pending Standard Technical Specification Change Traveler (TSTF) 439 which provides the following description and justification for not including the "second Completion Time" in the ITS:

The Improved Standard Technical Specifications (NUREGs 1430 through 1434) associated with all NSSS designs were issued in September 1992. A second Completion Time was included in the Completion Time for certain Required Actions to establish a limit on the maximum time allowed for any combination of Conditions of inoperability during any single continuous failure to meet the LCO. The intent of the second Completion Time was to preclude entry into and out of the ACTIONS for an indefinite period of time by providing a limit on the amount of time that the LCO could not be met for various combinations of Conditions.

The final Maintenance Rule, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was published by the Nuclear Regulatory Commission (NRC) in the Federal Register (56 Fed. Reg. 31324) as 10 CFR 50.65 on July 10, 1991. The Maintenance Rule became effective July 10, 1996, requiring full implementation by all licensees on that date.

The performance and condition monitoring activities required by 10 CFR 50.65(a)(1) and (a)(2) would identify if continuous multiple entries into the ACTIONS of the Technical Specifications results in unacceptable unavailability of these SSCs. The effectiveness of these performance monitoring activities, and associated corrective actions, is evaluated at least every refueling cycle, not to exceed 24 months per 10 CFR 50.65 (a)(3). This aspect of the Maintenance Rule requires adjustments to performance and condition monitoring activities, associated goals, and preventive maintenance activities to ensure that the objective of preventing failures of structures, systems, and components through maintenance is appropriately balanced against the objective of minimizing unavailability of structures, systems, and components due to monitoring or preventive maintenance.

Additionally, NEI 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline establishes Safety System Unavailability criteria for the AFW and Diesel Generators as a part of the Mitigating

Systems Cornerstone. Continuous multiple entries into these LCOs would be identified as part of the unavailability for these systems.

Based on the above discussions, the concern regarding multiple continuous entries into LCOs would be identified by the associated system unavailability monitoring programs described above, given that all licensees' Maintenance Rule programs include unavailability monitoring for the SSCs included in this evaluation. Therefore, this potential concern is no longer an issue, since all licensees have been required to comply with the Maintenance Rule since July 10, 1996. This obviates the need for the potential multiple continuous LCO entries that the second Completion Time was intended to prevent.

Entergy (IP2) Action:

None.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 4	**MB5068**

NRC Request for Additional Information (RAI):

The proposed SRs 3.8.1.7 and 8 verify manual transfer of AC power sources from the normal offsite circuit to the alternate offsite circuit and automatic transfer of AC power for 6.9 kV buses 2 and 3 from the unit auxiliary transformer to 6.9 kV buses 5 and 6 respectively. NUREG-1432 requires that these surveillances not be performed during Mode 1 and 2. Please provide justification for not having any Mode restrictions for these SRs.

Entergy (IP2) Response:

IP2 will revise ITS SR 3.8.1.7 and 3.8.1.8 to include the following Note: This SR shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced.

This restriction will make the IP2 ITS similar to the IP3 ITS.

Note that for ITS SR 3.8.1.8, an actual demonstration of the autotransfer feature requires tripping the main generator while the reactor is at power with the main generator supplying 6.9 kV buses 2 and 3. Credit may be taken for planned plant trips or for unplanned events that satisfy this SR. Additionally, in lieu of actually initiating a circuit transfer, testing that adequately shows the capability of the transfer is acceptable. This transfer testing may include any sequence of sequential, overlapping, or total steps so that the entire transfer sequence is verified.

Entergy (IP2) Action:

IP2 will revise ITS SR 3.8.1.7 and 3.8.1.8 to include the following Note: This SR shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 5	**MB5068**

NRC Request for Additional Information (RAI):

Required Action 3.8.1.A2 replaces the requirement of current technical specification 3.7.B.4 that "6.9 kV bus tie breaker control switches -- in the CCR (central control room) shall be placed in the "pull-out" position and tagged" with the requirement to disable the automatic transfer within 1 hour and re-verify every 8 hours thereafter. It is not clear to the staff as to how the operator will know that the switches are in the "pull-out position" if these switches are not tagged. Please justify for removing the current requirement of tagging the switches.

Entergy (IP2) Response:

CTS 3.7.B.4 requires that "When 6.9 kV buses 5 and 6 are supplied through a 13.8/6.9 kV transformer, in addition to satisfying the requirements of Specification 3.7.B.3 above, the 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the CCR shall be placed in the "pull-out" position and tagged to prevent an automatic transfer of the 6.9 kV buses 1, 2, 3 and 4."

ITS 3.8.1, Required Action A.2, replaces "6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the CCR shall be placed in the "pull-out" position and tagged" with "Verify automatic transfer of 6.9 kV buses 1, 2, 3 and 4 to 6.9 kV bus 5 and 6 is disabled."

Breakers in the "pull-out" position are easily identifiable to control room operators by the position of the switch.

IP2 will revise the markup of CTS 3.7.B.4 to show that the requirement that breaker controls in the "CCR shall be placed in the "pull-out" position and tagged" is deleted by ITS 3.8.1, DOC L.7. The justification will be that the required safety function is met when the automatic transfer is disabled. In conjunction with this change, IP2 will revise the Bases for ITS 3.8.1, Required Action A.2, to specify that breakers should be tagged in the pull out position if the automatic transfer function is expected to be disabled for more than one shift.

Entergy (IP2) Action:

IP2 will revise the markup of CTS 3.7.B.4 to show that the requirement that breaker controls in the "CCR shall be placed in the "pull-out" position and tagged" is deleted by ITS 3.8.1, DOC L.7.

IP2 will revise the Bases for ITS 3.8.1, Required Action A.2, to specify that breakers should be tagged in the pull out position if the automatic transfer function is expected to be disabled for more than one shift.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 6	**MB5068**

NRC Request for Additional Information (RAI):

The proposed LCO 3.8.1.A3 requires declaration of required feature(s) with no offsite power automatically available inoperable when its redundant required feature(s) is inoperable. Provide justification for not declaring required feature (s) inoperable when its redundant required feature(s) is inoperable when manually connected offsite power source is available.

Entergy (IP2) Response:

IP2 ITS LCO 3.8.1, Required Action A.3 (A.2 in the STS) for an inoperable offsite source, does require that required feature(s) that are supported only by a "delayed access" offsite circuit are declared inoperable when its redundant required feature(s) is inoperable.

STS (NUREG-1431) LCO 3.8.1, Required Action A.2 for an inoperable offsite source, reads as follows: "Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable." The completion Time is specified as follows: " 24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)."

IP2 ITS LCO 3.8.1, Required Action A.3 (A.2 in the STS) for an inoperable offsite source, reads as follows: "Declare required feature(s) with no offsite power 'automatically' available inoperable when its redundant required feature(s) is inoperable." The completion Time is specified as follows: " 24 hours from discovery of no offsite power 'automatically available' to one train concurrent with inoperability of redundant required feature(s)."

The differences between STS (NUREG-1431) LCO 3.8.1, Required Action A.2, and IP2 ITS LCO 3.8.1, Required Action A.3, are shown in the second paragraph in single quotation marks. These changes were made to emphasize the fact that availability to a "delayed access" will not be sufficient to prevent the inoperability of "required feature(s) with no offsite power automatically available inoperable when its redundant required feature(s) is inoperable." This is explained in detail in the Bases for ITS 3.8.1, Required Action 3, including Insert B 3.8.1 - 5 - 02.

Changes to STS (NUREG-1431) LCO 3.8.1, Required Action A.2, were necessary because IP2 has one "immediate access" and one "delayed access" offsite circuit and that IP2 has the option of connecting the 13.8 kV offsite circuit to 6.9 kV busses 5 and 6 which changes the delayed access circuit to an immediate access circuit for two of the three safeguards power trains (i.e., realigned per CTS 3.7.B.4) if needed when a redundant required feature is inoperable.

Entergy (IP2) Action:

None.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 7	**MB5068**

NRC Request for Additional Information (RAI):

It is stated that on a trip of the main generator, one or two reactor coolant pumps are supplied by the 13.8 kV offsite source and that the 13.8 kV source retains sufficient capacity to support ESF loads required in Modes 3 and 4. It is not clear to the staff if this source has enough capacity to supply these loads in Modes 1 and 2. Please clarify.

Entergy (IP2) Response:

IP2 has two offsite sources, a 138 kV source and a 13.8 kV source. The 138 kV source is normally aligned as an "immediate access" source (i.e., available within a few seconds). The 13.8 source is normally aligned as a "delayed access" source (i.e., available only after being aligned by operator action). The 138 kV source has sufficient capacity to support all four reactor coolant pumps and the ESF loads. The 13.8 kV source has sufficient capacity to support two reactor coolant pumps and the ESF loads. Offsite power comes into the plant via 6.9 kV buses 5 and 6 which, in turn, are used to power 6.9 kV buses 1 through 4. The four reactor coolant pumps are powered from 6.9 kV buses 1 through 4.

In Mode 2 (i.e., < 5% RTP), offsite power must be supplied by the 138 kV source (i.e., 6.9 kV buses 5 and 6 are supplied by the 138 kV source). Therefore, the four reactor coolant pumps (6.9 kV buses 1 through 4) are supplied by the 138 kV source via 6.9 kV buses 5 and 6.

When the plant transitions to Mode 1 (i.e., > 5% RTP), the power source for the four reactor coolant pumps (6.9 kV buses 1 through 4) is switched to the plants main generator via the Unit Auxiliary Transformer (UAT). However, 6.9 kV buses 5 and 6 are still supplied by the 138 kV source. If the plant or the main generator trips, the power source for the four reactor coolant pumps (6.9 kV buses 1 through 4) is automatically transferred back to 6.9 kV buses 5 and 6 (i.e., the 138 kV source).

If the 138 kV source becomes inoperable when in Mode 1, there is no "immediate access" source of offsite power to any of the three safeguards power trains (5A, 6A and 2A/3A). In this situation (i.e., offsite power not "automatically available" to an ESF load), ITS 3.8.1, Required Action A.3, would require that any ESF load without offsite power "automatically available" would have to be declared inoperable within 24 hours if the redundant feature is inoperable. Therefore, IP2 would elect the option of re-aligning the 13.8 kV source as the immediate access source (i.e., use 13.8 kV to supply 6.9 kV buses 5 and 6) so that there would be an immediate access source for two of the three safeguards power trains. However, the 13.8 kV source does not have sufficient capacity to support four reactor coolant pumps and the ESF loads if the main generator trips. Therefore, automatic transfer of the RCPs (i.e., 6.9 kV buses 1 through 4) from the main generator (i.e., the UAT) back to the offsite source (i.e., 6.9 kV buses 5 and 6 which are now being powered from 13.8 kV) has to be blocked. Blocking the automatic transfer of the RCPs to 6.9 kV buses 5 and 6 when 6.9 kV buses 5 and 6 are supplied by the 13.8 kV is the purpose of CTS 3.7.B.4 (i.e., tie breaker control switches 1-5, 2-5, 3-6 and 4-6 shall be in the pull out position and tagged) which is maintained in the ITS as LCO 3.8.1, Required Action A.2 (Verify automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to 6.9 kV bus 5 and 6 is disabled.) and the associated Note (Only required if 13.8 kV offsite circuit is supplying 6.9 kV bus 5 or 6 and the Unit Auxiliary Transformer is supplying 6.9

kV bus 1, 2, 3 or 4.) With the autotransfer feature blocked, the RCPs will trip on undervoltage and/or underfrequency when the main generator trips. After the RCPs have tripped, one or two RCPs may be started using the 13.8 kV offsite source.

In reviewing this RAI it was noted that DOC L.1 (last sentence (and paragraph) of the "Description of Change") contained an error that contributed to the need for the clarification sought by the RAI. Specifically the last sentence stated:

ITS 3.8.1, Required Action A.2 and associated Note, maintain the requirement to disable automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to the offsite source if the 13.8 kV offsite source is supplying 6.9 kV bus 5 or 6 except that ITS 3.8.1, Required Action A.2 Note, requires this restriction only if "the Unit Auxiliary Transformer is supplying 6.9 kV bus 2 or 3."

This should have stated:

...only if "the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4."

IP2 will revise DOC L.1 to change the last sentence of the "Description of Change," as described above.

Entergy (IP2) Action:

IP2 will revise DOC L.1 to change the last sentence of the "Description of Change," as described above.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 8	**MB5068**

NRC Request for Additional Information (RAI):

Please explain as to why the proposed change to verify that auto transfer is disabled within one hour rather than the current requirement to disable the automatic transfer performed prior to switching to the 13.8 kV offsite source is a more restrictive change.

In addition, please explain if the 13.8/6.9 kV source is capable of powering the safety loads for 1 hour in the event of a unplanned transfer.

Entergy (IP2) Response:

See also the response to RAI 3.8.1 - 7.

IP2 will revise ITS 3.8.1, DOC M.5, to identify this as less restrictive change DOC L.7 which will read as follows:

CTS 3.7.B.4 requires that the 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 are in the "pull-out" position when the 13.8 kV offsite source is being used to feed 6.9 kV buses 5 and 6. This requirement is needed because 6.9 kV buses 1, 2, 3, and 4, which supply power to the 4 reactor coolant pumps (RCPs), are powered directly from the IP2 main generator via the unit auxiliary transformer when the plant is at power; however, if the main generator trips, 6.9 kV buses 1, 2, 3, and 4 auto transfer to 6.9 kV buses 5 and 6 (fed from either the 138 kV or 13.8 kV offsite source). Although both the 138 kV offsite source and the 13.8 kV offsite source are sufficient to supply engineered safety feature (ESF) loads, only the 138 kV offsite source is capable of supporting both the ESF loads and 4 operating RCPs. Therefore, if the 13.8 kV offsite (alternate) source is being used to feed 6.9 kV buses 5 and 6, then CTS 3.7.B.3 requires that 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 are in the "pull-out" position. This restriction prevents overloading the 13.8 kV/6.9 kV auto-transformer with the RCPs if the main generator trips.

ITS LCO 3.8.1, Required Action A.2 and associated note, maintain the requirement to disable automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to the offsite source if the 13.8 kV offsite source is supplying 6.9 kV bus 5 or 6 except that ITS LCO 3.8.1, Required Action A.2, replaces the requirement that "CCR shall be placed in the "pull-out" position and tagged" with the requirement to disable the automatic transfer within 1 hour and re-verify every 8 hours thereafter. This results in two changes: ITS allows 1 hour to complete this requirement whereas the CTS does not specify a completion time; and, ITS requires re-verification that the action was completed every 8 hours but does not require that the breakers are "tagged."

Disabling the automatic transfer is performed prior to switching to the 13.8 kV offsite source and this activity is controlled by plant procedures. Establishing a 1 hour Completion Time to verify the automatic transfer has been disabled after switching to a 13.8 kV source is needed and is acceptable because it provides independent assurance in a timely manner that the activity was completed as required. Replacing a requirement to "tag" control switches with a requirement to re-verify that auto transfer is disabled every 8 hours is needed and is acceptable because ITS maintains the requirements that auto transfer is disabled and includes a more restrictive requirement to verify this status every 8 hours. Administrative controls intended to ensure Technical Specification requirements are met are left to the discretion of the plant staff and may vary depending on plant conditions. For example, it would be counter productive to hang and immediately remove tags if the intent is to restore the original lineup in a short period of time (e.g. before the end of the shift).

Entergy (IP2) Action:

IP2 will revise ITS 3.8.1, DOC M.5, to identify this as a less restrictive change DOC L.7.

3.8.1 : AC Sources - Operating

NRC RAI Number	TAC Number:
3.8.1 - 9	**MB5068**

NRC Request for Additional Information (RAI):

NUREG-1432 SR 3.8.1.18 requires verification that the interval between each sequenced load block is within ±10 % of design interval for each emergency load sequencer. The proposed change verifies that load sequence timer relay functions are within the required design interval. It is not clear to the staff why there is not any compensation provided for the load sequencer timer relay drift.

Entergy (IP2) Response:

CTS does not include an explicit requirement for periodic verification that load sequence timers are within required limits; however, this verification is performed in accordance with PT-R-13 every 24 months. This test procedure is supported by Calculation FEX-00039-01, and Section 4 of this calculation includes a listing of the sequence timers and the SR acceptance criteria which accounts for the timer accuracy. The SR acceptance criteria is specified as an acceptable interval at the time the test is performed (e.g., 2 to 4 seconds, 7 to 9 seconds, 14 to 16 seconds, 19 to 21 seconds, etc.)

Entergy (IP2) Action:

None.