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December 16, 2010

NL-10-133

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

SUBJECT: Supplement to Proposed License Amendment to Change Technical Specifications Regarding Surveillance Requirements For AC and DC Sources (TAC No. ME2869)
Indian Point Unit Number 3
Docket No. 50-286
License No. DPR-64

REFERENCE:
1 Entergy Letter NL-09-129 to NRC, "Proposed License Amendment to Change Technical Specifications Regarding Surveillance Requirements For AC and DC Sources," dated November 19, 2009.

2 Entergy Letter NL-09-172 to NRC, "Supplement to Proposed License Amendment to Change Technical Specifications Regarding Surveillance Requirements For AC and DC Sources (TAC No. ME2869)," dated December 22, 2009.

Dear Sir or Madam:

Entergy Nuclear Operations, Inc, (Entergy) requested a License Amendment to Operating License DPR-64, Docket No. 50-286 for Indian Point Nuclear Generating Unit No. 3 (IP3) in Reference 1 as supplemented by Reference 2. The proposed amendment will revise the test acceptance criteria specified in Surveillance Requirement (SR) 3.8.1.10 for the Diesel Generator endurance surveillance test, revise the surveillance to reflect modifications to the surveillance by TSTF-276-A, Revision 2, and make additional changes to various notes in SR in 3.8.1 and 3.8.4 to reflect changes made by TSTF-283-A, Revision 3.

In Reference 1 Entergy requested 30 days be allowed for implementation. Entergy would like to modify this to request immediate effectiveness with implementation in 120 days. This would place IP3 in an outage when the SR 3.8.1.10 tests are first performed to the revised TS.

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In addition, during a November 18, 2010 phone call, Entergy discussed with the NRC how to address any difficulties that occur meeting power factor requirements when tied to the 13.8 kV offsite power line. Agreement was reached to add a fourth note to SR 3.8.1.10 to address this concern. Also discussed in that phone call was the desire to increase the lower band of the kW loading in the first 105 minutes of SR 3.8.1.10.

Entergy has revised the evaluation of the proposed change in accordance with 10 CFR 50.91 (a)(1) that was submitted in Reference 1 in order to address changes from Reference 2, the addition of note 4 and the change to the lower band of the loading (Attachment 1). Changes have bars in the right column. Entergy concludes that the changes do not affect the previous conclusion that there are no significant hazards considerations. The information in References 1 and 2 is supplemented with resubmittal of the proposed changes to SR 3.8.1.10 in Attachment 2 and, for information, the Bases for Chapter 3.8.1 are in Attachment 3.

If you have any questions or require additional information, please contact Mr. Robert Walpole, Manager, Licensing at (914) 734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on December 16, 2010.

Sincerely,

Patrick W. Conroy acting for J. Pollock

JEP/sp

cc: Mr. John P. Boska, Senior Project Manager, NRC NRR DORL
Mr. William Dean, Regional Administrator, NRC Region 1
NRC Resident Inspectors
Mr. Francis J. Murray, Jr., President and CEO, NYSERDA
Mr. Paul Eddy, New York State Dept. of Public Service

Attachments:

1. Analysis of Proposed Technical Specification Change Regarding Surveillance Requirements For AC and DC Sources
2. Markup of Technical Specification Page for Proposed Changes Regarding Surveillance Requirement 3.8.1.10 for Chapter 3.8.1
3. Markup of Technical Specification Bases for Proposed Changes Regarding Surveillance Requirements for Chapter 3.8.1

ATTACHMENT 1 TO NL-10-133

ANALYSIS OF PROPOSED TECHNICAL SPECIFICATION CHANGES

REGARDING

SURVEILLANCE REQUIREMENTS FOR AC AND DC SOURCES

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

1.0 DESCRIPTION

Entergy Nuclear Operations, Inc (Entergy) is requesting an amendment to Operating License DPR-64, Docket No. 50-286 for Indian Point Nuclear Generating Unit No. 3 (IP3). The proposed change will revise the test acceptance criteria specified in SR 3.8.1.10 for the Diesel Generator endurance run surveillance. Changes in the load ranges and power factors specified for the test are proposed for consistency with the corrective actions taken by Entergy to address NRC inspection results and to correct the non conservative specification. Changes are made to notes 2 and 3 of SR 3.8.1.10 as well as to the notes of other surveillance requirements in TS 3.8.1 and 3.8.4 to reflect changes to the Standard Technical Specifications (STS), Reference 1, made by Technical Specification Task Force (TSTF)-283-A, Revision 3 and TSTF-276-A, Revision 2. These were both incorporated into Revision 2 of NUREG-1431. An additional note 4 is added to SR 3.8.1.10 to provide additional guidance when testing while tied to 13.8kV offsite power.

2.0 PROPOSED CHANGES

The surveillance test acceptance criteria in Diesel Generator Surveillance SR 3.8.1.10 will be revised from:

"-------------------NOTES--------------------
1. Momentary transients outside the load and power factor ranges do not invalidate this test.
2. This Surveillance shall not be performed in MODE 1 or 2.

Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 8 hours:

a. For ≥ 105 minutes loaded ≥ 1837 kW and ≤ 1925 kW; and
b. For the remaining hours of the test loaded ≥ 1575 kW and ≤ 1750 kW."

To:

"-------------------NOTES--------------------
1. Momentary transients outside the load and power factor ranges do not invalidate this test.
2. This Surveillance 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. If performed with DG synchronized with offsite power, it shall be performed at a power factor of ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and ≤ 0.84 for EDG 33. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable.
4. Prior to performing SR 3.8.1.10 while connected to the 13.8 kV offsite power, the grid condition must be evaluated to show that conditions exist to reasonably allow the required power factor limits to be met or perform the SR while connected to the 138 kV offsite power.

Verify each DG operates for ≥ 8 hours:

a. For ≥ 105 minutes loaded ≥ 1925 kW and ≤ 1941 kW; and

b. For the remaining hours of the test loaded ≥ 1700 kW and ≤ 1750 kW."

The SR 3.8.1.7 note, the SR 3.8.1.8 note 1, and the SR 3.8.1.9 note will be revised from:

"This Surveillance shall not be performed in MODE 1 or 2."

To:

"This Surveillance 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."

The SR 3.8.1.12 note 2, and the SR 3.8.4.2 note will be revised from:

"This Surveillance shall not be performed in MODE 1, 2, 3, or 4."

To:

"This Surveillance shall not normally be performed in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced."

The marked up Technical Specification pages for these changes is provided in Attachment 2. The associated Technical Specification Bases changes are included in Attachment 3 for information.

3.0 BACKGROUND

IP3 Technical Specification (TS) Surveillance Requirement (SR) 3.8.1.10 is a test of the emergency diesel generators (EDG), similar to Standard Technical Specification (STS), Reference 1, SR 3.8.1.14. This surveillance requires that each DG be started and loaded for a specified period of time at specified loading conditions, which include kilowatt (kW) output and power factor. Prior to conversion to STS, called the Improved Technical Specification (ITS), the Custom Technical Specifications (CTS) contained a requirement for diesel testing (Specification 4.6.A.2) which stated:

> "At least once per 24 months each diesel generator shall be manually started, synchronized and loaded up to its 2 hour rating and run for a period of at least 105 minutes."

The CTS Bases stated:

> "Each diesel has a continuous rating of 1750 kw and a 2 hour rating of 1950 kw. Two diesels can power the minimum safeguards loads. To ensure that each diesel can operate at its 2 hour rating, (as required by specification 4.6.A.2.), each diesel will be loaded to 1900-1950 kw and run for at least 105 minutes."

This CTS testing requirement was based on the diesel generator design. As noted in the original FSAR Section 8.2.3, "the on-site sources of emergency power are three emergency diesel-generator sets, each consisting of an Alco model 16-251-E engine coupled to a Westinghouse 2188 kva, 0.8 power factor, 900 rpm. 3 phase, 60 cycle 480 volt generator. The units have a capability of 2000 kw peaking and 1750 kw continuous." The UFSAR has been revised to indicate the continuous rating is 1750 kW, the two hour rating is 1950 kW and the ½ hour rating is 2000 kW to account for power surges and spikes.

During the conversion to ITS, the CTS requirement was expanded to specify test acceptance criteria in the TS surveillance including acceptance criteria for test duration and power factor. The loading requirement for this test was modified to specify two test intervals; the added time from 105 minutes to 8 hours was at a load range that corresponds to 90% - 100% of the DG continuous rating and the period up to 105 minutes was at a load range that corresponds to 105% - 110% of the DG continuous rating. The power factor of 0.9 was selected based on the PF bracketed in the STS.

During NRC inspection activities described in Reference 2, questions were raised regarding the adequacy of the TS surveillance acceptance criteria and engineering analyses for EDG loading in which the most limiting design input values were not used. An evaluation at the time determined that the maximum possible load using the most limiting design inputs would be 1924.4 kW for EDG 32. Therefore the TS load profile did not ensure testing was to at least the maximum possible load. As a result Entergy determined the SR 3.8.1.10 was non conservative and there was a need to submit a license amendment request to establish new load ranges that would bound the peak accident loads. Entergy is proposing to revise SR 3.8.1.10 so that the proposed new load ranges bound the peak accident loads.

When investigating the above changes regarding DG kW loading, Entergy determined that a change to the power factor test value is also appropriate. At IP3, the emergency diesel generator and associated electrical distribution system is a 480 volt system. Surveillance testing cannot be performed using the 480 V loads that would be powered under an accident scenario; rather the loading of the DG must be accomplished by picking up load from the offsite grid. This involves step-up transformers from 480 V to 6.9 kV and then additional step-up to either 13.8 kV or 138 kV, depending on which feeder circuits are available between the station and the grid. The proposed change will reflect the revised calculations.

The SR is also being revised for consistency with the current STS which incorporate: the allowance to perform the test in Mode 1 or 2 when required to reestablish operability and a safety assessment concludes it can be done safely; and, an allowance to test at higher than the calculated power factor where offsite conditions do not allow. This is consistent with IP2.

4.0 <u>TECHNICAL ANALYSIS</u>

4.1 Load Range

The IP3 TS SR 3.8.1.10 does not ensure testing to the peak loading conditions in the IP3 calculations. The peak loading conditions were identified in calculation IP3-CALC-ED-00207, Rev 7 (Reference 3). The evaluation accounts for the time-dependent electrical power requirements of various safeguards components as the accident scenario progresses. During the NRC inspection (Reference 2) the peak loading calculations in Reference 3 were found to be in error because they used non conservative brake horsepower values and did not account for the maximum frequency limit allowed by the TS of 61.2 Hz. Corrective action was taken initially to define a bounding Emergency Diesel Generator load and demonstrate operability by testing. The EDG frequency is currently being administratively controlled between 59.7 Hz and 60.3 Hz. The effect of an increase in the load due to an over frequency of 60.3 Hz is addressed on page 53 of Reference 3. Since that time, the brake horsepower (BHP) calculations were reviewed and revised (References 4 and 5). They addressed the concerns raised in the inspection and incorporated the changes due to recirculation pump replacement. IP3-CALC-ED-00207 was then revised (Reference 6) to incorporate revised BHP calculations and the worst case loading is still 32EDG (see pages 56 to 58). The bounding value of 1924.4 kW has dropped to a maximum loading of 1915.15 kW and EDG 31 and 33 have smaller maximum loads of 1868.55 kW and 1691.9 kW, respectively. All three diesels are below 1700 kW within 105 minutes for the remainder of the time which is within the continuous rating of 1750 kW.

The proposed new SR acceptance criterion of ≥ 1925 kW to ≤ 1941 kW for ≥ 105 minutes bounds these peak loading conditions, without exceeding the EDG 2 hour rating limit. The proposed new SR acceptance criterion of ≥ 1700 kW to ≤ 1750 kW for the balance of the eight hours bound the calculated loads, without exceeding the continuous rating limit of 1750 kW.

The revised loading for the ST is not the source of any accident and cannot create a new kind of accident because there is no change to operation not previously considered in design. The enhanced load testing more accurately tests the diesels to calculated conditions and therefore does not reduce the margin or create the possibility of increasing accident consequences.

4.2 Power Factor

The revised power factor for the ST is not the source of any accident and cannot create a new kind of accident because there is no change to operation not previously considered in design. The revised power factor more accurately tests the diesels to calculated conditions and therefore does not reduce the margin or increase the probability of consequences for an accident previously evaluated. The existing TS SR 3.8.1.10 acceptance criterion for power factor (≤ 0.90) was used because the STS had this value in brackets indicating plant specific numbers were used and insufficient analysis was used to determine the correct number. Prior to conversion to the ITS, a test acceptance criterion for power factor was not specified. The power factor assumed in the load calculations (Reference 3) was 0.85. When Entergy revised the loading calculation (Reference 6) the power factor was revised as well (see pages 57 to 59). The revised PF of ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32 and ≤ 0.84 for EDG 33 have been incorporated into the SR acceptance criteria.

Entergy has determined that these power factor values are achievable when tied to the 138 kV offsite power source under the test conditions applicable for this surveillance based on a review of past test results. When tied to the 13.8 kV offsite power source there can be problems meeting the power factor during periods of high grid voltage because the 13.8 kV transformer does not have an adjustable tap changer and therefore the PF has to be controlled by regulation of the grid. The EDG are normally synchronized to the 138 kV offsite power source for testing. However, there may be times during an outage when testing is required and the EDG must be synchronized to the 13.8 kV offsite power source. Past practice has been to retest the EDG while attached to the 138 kV offsite power source at a later time if the power factor is not met. To reflect this, note 4 was added to SR 3.8.1.10 to assess the 13.8 kV circuit before testing the EDG to assure there was reasonable assurance of meeting the power factors. Since the test has not been performed with these power factors before, the assessment of the circuit may require several tests to become more certain. If the power factor was not met the EDG is still operable and may be tested when tied to the 138 kV offsite power.

The revised power factor for the ST is not the source of any accident and cannot create a new kind of accident because there is no change to operation not previously considered in design. The revised power factor more accurately tests the diesels to calculated conditions and therefore does not reduce the margin or create the possibility of increasing accident consequences.

4.3 TSTF-276-A and TSTF-283-A

Technical Specification Task Force (TSTF) -276-A, Revision 2 was approved on August 30, 2000. Notes were added to STS surveillances 3.8.1.9, 3.8.1.10, and 3.8.1.14 and incorporated into Revision 2 of the STS, dated April 30, 2001. The note added to each SR indicated that performance of the SR with the diesel synchronized to offsite power should be performed at the required power factor but this power factor need not be met if grid conditions do not allow. The power factor should still be maintained as close as possible to the required value. The bases were revised as well.

TSTF-283-A, Revision 3 was approved on April 13, 2000. Notes were added to STS surveillances 3.8.1.8, 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.13, 3.8.1.14, 3.8.1.16, 3.1.8.17, 3.8.1.18, 3.8.1.19, 3.8.4.6, 3.8.4.7 and 3.8.4.8 in Revision 2 of the STS, dated April 30, 2001. The note added to each SR modified the statement that the surveillance "shall not be performed in MODE 1 or 2" or shall not be performed in MODE 1,2,3, or 4" and allowed the surveillance to be performed to reestablish operability provided an assessment determines the safety of the plant is maintained or enhanced. The bases were revised as well.

The initial ITS for IP3 was developed using Revision 1 of the STS, dated April 7, 1995. Many of the travelers added to revision 2 of the STS were included but not all of them. TSTF-276-A, Revision 2 is applicable to IP3 because EDG testing is performed when synchronized to offsite power, either 138 kV or 13.8 kV. TSTF-283-A, Revision 3 is applicable to IP3 because it is not based on specific plant conditions. The change requires an evaluation of specific circumstances before performing the surveillance in an off normal mode. The evaluation is required to demonstrate the testing can be done in a safe manner and it is only used for flexibility to reestablish operability.

The IP3 SRs that are being revised adopt the notes of the STS SRs modified by the two TSTF as follows:

Revised IP3 TS Section	Equivalent STS Section Affected by TSTF-276-A	Equivalent STS Section Affected by TSTF-283-A
3.8.1.7 and 3.8.1.8		3.8.1.8
3.8.1.9		3.8.1.13
3.8.1.10	3.8.1.14	3.8.1.14
3.8.1.12		3.8.1.11
3.8.4.2		3.8.4.6

There are two exceptions taken to TSTF-283-A. In SR 3.8.1.8 and SR 3.8.1.13, the note said "shall not be normally performed" rather than "shall not normally be performed" used everywhere else. The IP3 SR were all revised using "shall not normally be performed" for consistency. Also, the TSTF-283-A SR Bases inserts 1 and 2 said "This restriction from normally performing the

Surveillance in MODE 1 or 2...." However the inserts 1 and 2 were applied to some SR that had restrictions from performing in Modes 1, 2, 3, and 4. In those cases the bases inserts were revised to say "This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 " to reflect the TS change.

The revised allowance to perform a test without meeting the power factor recognizes the limitations that may be imposed by grid conditions. Not meeting the power factor is not the source of any accident and cannot create a new kind of accident because there is no change to operation not previously considered in design. Not meeting the power factor tests the diesel to conditions close to conservative accident assumptions and demonstrates operability with no significant degradation of margin or creating the possibility of increasing accident consequences. Similarly, the modifications made to the SR notes that allow full or partial testing in modes not normally performed is not going to increase the probability of accidents or create a new type of accident because the tests must be evaluated to ensure the safety of the plant is maintained or enhanced. There is no probability of increased consequences of accidents or significant reductions in safety margin because the equipment required to mitigate accidents will be tested to demonstrate its operability.

5.0 **REGULATORY ANALYSIS**

5.1 No Significant Hazards Consideration

Entergy Nuclear Operations, Inc. (Entergy) has evaluated the safety significance of the proposed change to the Indian Point 3 Technical Specification that revises EDG load testing and power factor requirements. This proposed change has been evaluated according to the criteria of 10 CFR 50.92, "Issuance of Amendment". Entergy has determined that the subject change does not involve a Significant Hazards Consideration as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   No. The proposed changes revise the acceptance criteria to be applied to an existing surveillance test of the facility emergency diesel generators (EDGs), allows deviation from that acceptance criteria for certain grid conditions, and allows testing in modes that is normally not done. Performing a surveillance test is done under conditions where it is not an accident initiator and does not increase the probability of an accident occurring. The proposed new acceptance criteria will assure that the EDGs are capable of carrying the peak electrical loading assumed in the various existing safety analyses which take credit for the operation of the EDGs. Establishing acceptance criteria that bound existing analyses validates the related assumption used in those analyses regarding the capability of equipment to mitigate accident conditions. The deviation allowed for grid conditions does not affect the capability of the testing to achieve these purposes. The proposed change to allow testing in modes normally restricted requires an evaluation to ensure, prior to performing the test, that the potential consequences are capable of being addressed by existing procedures and does not create transients or conditions that could significantly affect the possibility of an accident. Therefore the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   No. The proposed changes revise the test acceptance criteria for a specific performance test conducted on the existing EDG, allows deviation from that acceptance criteria for certain grid conditions, and allows testing in modes that is normally not done. The proposed changes do not involve installation of new equipment or modification of existing equipment, so no new equipment failure modes are introduced. The proposed revision to the EDG surveillance test acceptance criteria also is not a change to the way that the equipment or facility is operated and no new accident initiators are created. The proposed testing on line must be evaluated to assure plant safety is maintained or enhanced, inherent in such an evaluation would be that the testing does not create the possibility of a new or different kind of accident. Therefore the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   No. The conduct of performance tests on safety-related plant equipment is a means of assuring that the equipment is capable of maintaining the margin of safety established in the safety analyses for the facility. The proposed change in the EDG technical specification surveillance test acceptance criteria is consistent with values assumed in existing safety analyses and is consistent with the design rating of the EDGs. The allowance for certain grid conditions does not alter this conclusion since the power factors are conservatively determined. Testing allowed in modes when it is not normally performed is limited to conditions where an evaluation is performed to assure plant safety is maintained or enhanced. Therefore the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment to the Indian Point 3 Technical Specifications presents no significant hazards consideration under the standards set forth in 10 CFR 50.92 (c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements / Criteria

General Design Criterion (GDC) 17; "Electric Power Systems" requires that onsite electric power systems have sufficient independence, capacity, capability, redundancy, and testability to ensure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents, assuming a single failure.

GDC 18; "Inspection and Testing of Electric Power Systems" requires that electric power systems important to safety be designed to permit appropriate periodic inspection and testing to assess the continuity of the systems and the condition of their components.

IP3 Final Safety Analysis Report (FSAR) section 1.3 describes how the requirements of GDC 17 and 18 are met at IP3. Also, Technical Specification section 3.8.1 contains testing requirements for the DGs.

Regulatory Guide 1.9, Revision 3 describes methods for meeting the above requirements based on NRC staff endorsement of IEEE Standard 387-1984, with exceptions as stated in the Regulatory Guide. Regulatory Position 2.2 describes various DG tests, including test 2.2.9 for the Endurance and Margin Test. The loading requirements for this test are specified as a percentage of the continuous rating of the DGs, and these load ranges (105% - 110% of continuous rating and 90% - 100% of continuous rating) are specified in the existing technical specification surveillance requirement (SR) 3.8.1.10. In the conversion to Improved Technical Specifications Entergy adopted test ranges based on Regulatory Guide 1.9. However, these ranges did not bound the peak DBA loading. Therefore, Entergy is proposing to revise the power factor and test load ranges specified for SR 3.8.1.10 based on the continuous and short term ratings defined in the plant design. Testing at these ranges will assure that applicable criteria are met.

5.3 Environmental Considerations

The proposed changes to the IP3 Technical Specifications do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 PRECEDENCE

Indian Point Unit 2 has established power factors and EDG load requirements in the SR that ensure testing is to accident loads. These were approved in NRC letter dated April 22, 2009. Revision 2 of the STS adopted TSTF-276-A, Revision 2, and TSTF-283-A, Revision 3.

7.0 REFERENCES

1. Standard Technical Specifications for Westinghouse plants, NUREG 1431
2. NRC Inspection Report 05000286/ 2007006, dated February 7, 2008
3. IP3-CALC-ED-00207, Revision 7, "480V Bus 2A, 3A, 5A, and 6A and EDG's 31, 32 and 33 Accident loading."
4. IP-CALC-04-00809, Revision 2, "Brake Horsepower Values Related to Certain Pumps and Fans for EDG Electrical Loading."
5. CN-CRA-08-11, Revision 0 - "Indian Point Unit 3 Fan Cooler Unit (FCU) Horsepower Under LOCA Conditions."
6. IP3-CALC-ED-00207, Revision 8, "480V Bus 2A, 3A, 5A, and 6A and EDG's 31, 32 and 33 Accident loading."

ATTACHMENT 2 TO NL-10-133

MARKUP OF TECHNICAL SPECIFICATION PAGE FOR PROPOSED CHANGES

REGARDING

SURVEILLANCE REQUIREMENT 3.8.1.10 FOR CHAPTER 3.8.1

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ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
3.8.1.10	-----------------------NOTES----------------------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance 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. If performed with DG synchronized with offsite power, it shall be performed at a power factor of ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and ≤ 0.84 for EDG 33. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable.*** ***4. Prior to performing SR 3.8.1.10 while connected to the 13.8 kV offsite power, the grid condition must be evaluated to show that conditions exist to reasonably allow the required power factor limits to be met or perform the SR while connected to the 138 kV offsite power.*** ---	
	Verify each DG ~~operating at a power factor≤ 0.9~~ ***operates*** for ≥ 8 hours: a. For ≥ 105 minutes loaded ≥ ~~1837~~ ***1925***kW and ≤ 19~~25~~***41*** kW; and b. For the remaining hours of the test loaded≥ ~~1575~~ ***1700***kW and ≤ 1750 kW.	24 months
SR 3.8.1.11	-----------------------NOTE----------------------- Load timers associated with equipment that has automatic initiation capability disabled are not required to be operable ---	
	Verify each time delay relay functions within the required design interval	18 months

(continued)

ATTACHMENT 3 TO NL-10-133

MARKUP OF TECHNICAL SPECIFICATION BASES FOR PROPOSED CHANGES

REGARDING

SURVEILLANCE REQUIREMENTS FOR CHAPTER 3.8.1

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ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources – Operating

BASES

BACKGROUND

The unit Electrical Power Distribution System AC sources consist of the following: two offsite circuits (the normal or 138 kV circuit and the alternate or 13.8 kV circuit), each of which has a preferred and backup feeder; and, the onsite standby power circuit consisting of three diesel generators. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite plant distribution system is configured around 6.9 kV buses Nos. 1, 2, 3, 4, 5, and 6. All offsite power to safeguards buses enter the plant via 6.9 kV buses Nos.5 and 6 which are connected to the 138 kV (normal) offsite circuit and have the ability to be connected to the 13.8 kV (alternate) offsite circuit. 6.9 kV buses 1, 2, 3, and 4, which supply power to the 4 reactor coolant pumps (RCPs), typically receive power from the main generator via the unit auxiliary transformer (UAT) when the plant is at power. However, when the main generator or UAT is not capable of supporting this arrangement, 6.9 kV buses 1 and 2 receive offsite power via 6.9 kV bus 5 and 6.9 kV buses 3 and 4 receive offsite power via 6.9 kV bus 6. Following a unit trip, 6.9 kV buses 1, 2, 3, and 4 will auto transfer (fast transfer) to 6.9 kV buses 5 and 6 in order to receive offsite power. The 6.9 kV buses supply power to the 480 V buses using 6.9 kV/480 V station service transformers (SSTs) as follows: 6.9 kV bus 5 supplies 480 V bus 5A via SST 5; 6.9 kV bus 6 supplies 480 V bus 6A via SST 6; 6.9 kV bus 2 supplies 480 V bus 2A via SST 2; and, 6.9 kV bus 3 supplies 480 V bus 3A via SST 3.

The onsite AC Power Distribution System begins with 480 V buses 5A, 6A, 2A and 3A and is divided into 3 safeguards power trains (trains) consisting of the 480 volt safeguards bus(es) and associated AC electrical power distribution subsystems, 125 volt DC bus subsystems, and 120 volt vital AC instrument bus subsystems. The three trains are designed such that any two trains are capable of meeting minimum requirements for accident mitigation and/or safe shutdown. The three safeguards power trains are train 5A (480 volt bus 5A and associated DG 33), train 6A (480 volt bus 6A and associated DG 32), and train 2A/3A (480 volt buses 2A and 3A and associated DG 31).

(continued)

BASES

BACKGROUND (continued)

Offsite power is supplied to the plant from the transmission network by two electrically and physically separated circuits, the 138 kV or normal circuit and the 13.8 kV or alternate circuit. Each of the offsite circuits from the Buchanan substation into the plant is required to be supported by a physically independent circuit from the offsite network into the Buchanan substation. All offsite power enters the plant via 6.9 kV buses Nos.5 and 6 which are connected to the 138 kV (normal) offsite circuit and have the ability to be connected to the 13.8 kV (alternate) offsite circuit. This arrangement satisfies the requirement that at least one of the two required circuits can within a few seconds, provide power to safety-related equipment following a loss-of-coolant accident. Operator action is required to supply offsite power to the plant using the 13.8 kV (alternate) offsite source.

The 138 kV circuit and the 13.8 kV circuit each have a preferred and a backup feeder that connects the circuit to the Buchanan substation. For both the 138 kV and 13.8 kV circuits, the preferred IP3 feeder is the backup IP2 feeder and the backup IP3 feeder is the preferred IP2 feeder.

For the 138 kV (i.e., normal) offsite circuit, IP2 and IP3 each have a dedicated Station Auxiliary Transformer (SAT) that can be supplied by either a preferred or backup feeder. The normal or 138 kV offsite circuit, including the SAT used exclusively for IP3, is designed to supply all IP3 loads, including 4 operating RCPs and ESF loads, when using either the preferred (95331) or backup (95332) feeder. There are no special restrictions when IP2 and IP3 are both using the same 138 kV feeder concurrently.

For the 13.8 kV (i.e., alternate) offsite circuit, there is a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W92 and a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W93.

Feeder 13W93 and its associated auto-transformer is the preferred feeder for the IP3 alternate (13.8 kV) circuit and the backup feeder for the IP2 alternate (13.8 kV) circuit. Feeder 13W92 and its associated auto-transformer is the backup feeder for the IP3 alternate (13.8 kV) circuit and the preferred feeder for the IP2 alternate (13.8 kV) circuit.

(continued)

BASES

BACKGROUND (continued)

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite 480 V ESF bus(es).

The onsite standby power source consists of 3 480 V diesel generators (DGs) with a separate DG dedicated to each of the safeguards power trains. Safeguards power train 5A (480 V bus 5A) is supported by DG 33; safeguards power train 6A (480 V bus 6A) is supported by DG 32; and, safeguards power train 2A/3A (480 V buses 2A and 3A) is supported by DG 31. A DG starts automatically on a safety injection (SI) signal or on an ESF bus undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by individual load timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of 138 kV or normal offsite source, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for DGs 31, 32 and 33 are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). The 3 DGs each consist of an Alco model 16-251-E engine coupled to a Westinghouse 2188 kVA, 0.8 power factor, 900 rpm, 3 phase, 60 cycle, 480 volt generator. The ESF loads that are powered from the 480 V ESF buses are listed in Reference 2.

(continued)

BASES

BACKGROUND (continued)

The EDGs have four capacity ratings as defined below that can be used to assess EDG operability.

Continuous: Electrical power output capability that can be maintained 24 hours /day, with no time constraint.

2000-hour: Electrical power output capability that can be maintained in one continuous run of 2000 hours or in multiple shorter duration runs totaling 2000 hours.

2-hour: Electrical power output capability that can be maintained for up to 2 hours in any 24-hour period.

1/2 - hour: Electrical power output capability that can be maintained for up to 30 minutes in any 24-hour period.

The electrical output capabilities (EDG load) applicable to these four ratings are as follows:

RATING	EDG LOAD	TIME CONSTRAINT
Continuous	≤ 1750 kW	None
2000-hour	≤ 1950 kW	≤ 2000 hours / calendar year
2-hour	≤ 1950 kW	≤ 2 hours in a 24-hour period; AND
	≤ 1750 kW	for the remaining 22 hours. [See NOTE A]
1/2-hour	≤ 2000 kW	≤ 30 minutes in a 24-hour period; AND
	≤ 1750 kW	for the remaining 23.5 hours. [See NOTE A]

(continued)

BASES

BACKGROUND (continued)

NOTE A: The loading cycle permitted for the '2-hour' and the '1/2-hour' rating is operation at the overload condition (e.g. > 1750 kW) for the specified time followed by operation at the 'continuous' (e.g. ≤ 1750kW) rating for the remaining time in the 24-hour period. This loading cycle may be repeated each day, as long as back-to-back operation in the overload condition does not occur. The 2000-hour cumulative time constraint also applies to repetitive operation at the overload conditions allowed by the 2-hour and the 1/2-hour ratings.

Operation in excess of 2000 kW, regardless of the duration, is an unanalyzed condition. In such cases, the EDG is assumed to be inoperable and the vendor should be consulted to determine if accelerated or supplemental inspection and/or maintenance is necessary. The EDG can be returned to an operable status following completion of vendor-required inspection and/or maintenance.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power

Distribution Limits; 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least 2 of the 3 safeguards power trains energized from either onsite or offsite AC sources during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

(continued)

BASES

LCO

Two qualified circuits between the offsite transmission network and the onsite Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

There are two qualified circuits (normal and alternate) from the transmission network at the Buchanan Station to the onsite electric distribution system. The normal circuit is 138 kV and the alternate circuit is 13.8 kV. If the alternate circuit is in use, the normal circuit is inoperable because the autotransfer functions mentioned in the following circuit descriptions are disabled. Both of these circuits must be supported by a circuit from the offsite network into the Buchanan substation that is physically independent from the other circuit to the extent practical. The circuits into the Buchanan substation that satisfy these requirements are 96951, 96952 and 95891.

The 138 kV (i.e., normal) offsite circuit consists of one of the following: 138 kV feeder 95331 (preferred); or, 138 kV feeder 95332 (backup). Additionally, the 138 kV/6.9 kV station auxiliary transformer, circuit breakers ST5 and ST6 which supply 6.9 kV buses 5 and 6, and the following components which are common to the normal and alternate offsite circuits:

a. The 480 V bus 5A supply consisting of 6.9 kV bus 5, station service transformer 5, and circuit breakers SS5 and 52/5A;

b. The 480 V bus 2A supply consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (including autotransfer function), 6.9 kV bus 2, station service transformer 2, and circuit breakers SS2 and 52/2A;

c. The 480 V bus 6A supply consisting of 6.9 kV bus 6, station service transformer 6, and circuit breakers SS6 and 52/6A; and,

d. The 480 V bus 3A supply consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (including autotransfer function), 6.9 kV bus 3, station service transformer 3, and circuit breakers SS3 and 52/3A.

(continued)

LCO (continued)

The 13.8 kV (i.e., alternate) offsite circuit consists of one of the following: 13.8 kV feeder 13W93 and its associated 13.8/6.9 kV autotransformer (preferred); or, 13.8 kV feeder 13W92 and its associated 13.8/6.9 kV autotransformer (backup). Circuit breakers GT35 and GT36, which supply 6.9 kV buses 5 and 6, and the following components are common to the normal and alternate offsite circuits:

a. The 480 V bus 5A supply consisting of 6.9 kV bus 5, station service transformer 5, and circuit breakers SS5 and 52/5A;

b. The 480 V bus 2A supply consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (not including autotransfer function), 6.9 kV bus 2, station service transformer 2, and circuit breakers SS2 and 52/2A;

c. The 480 V bus 6A supply consisting of 6.9 kV bus 6, station service transformer 6, and circuit breakers SS6 and 52/6A; and,

d. The 480 V bus 3A supply consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (not including autotransfer function), 6.9 kV bus 3, station service transformer 3, and circuit breakers SS3 and 52/3A.

If the alternate (13.8 kV) offsite circuit is being used to supply power to the plant and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4, the size of the 13.8 kV/6.9 kV auto-transformers requires that the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to 6.9 kV buses 5 and 6 (i.e., the offsite circuit) be disabled because neither 13.8 kV/6.9 kV auto-transformer is capable of supplying 4 operating RCPs. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the alternate offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded by these manual actions.

If IP3 and IP2 are both using a single 13.8 kV feeder (13W92 or 13W93), administrative controls are used to ensure that the 13.8 kV/6.9 kV auto-transformer load restrictions will not be exceeded.

Operability of the offsite power sources requires the ability to provide the required capacity during design basis conditions. The minimum offsite voltage necessary to provide the required capacity

(continued)

BASES

LCO (continued)

was determined, using system load flow studies with conservative assumptions (Reference 10), to be greater than or equal to 136 kV and 13.4 kV for the 138 kV and 13.8 kV circuits, respectively. Upon notification by Con Ed that these alarm limits are not met, the LCO is considered not met at the time of the initial alarm. When the grid monitoring system is operating the minimum acceptable 138 kV voltage varies with grid conditions and Con Ed will provide notification.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

Three DGs must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in each safeguards power train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, and not violate separation criteria. A circuit that is not connected to an ESF bus is required to have OPERABLE automatic or manual transfer capability to the ESF buses to support OPERABILITY of that circuit.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and
b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

(continued)

APPLICABILITY (continued)

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources – Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG or the 138 kV offsite circuit. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG. This also applies to the 138 kV offsite circuit, which is the only immediate access offsite circuit. Therefore, the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. For activities that will require entry into the associated Condition, performance of SR 3.8.1.1 for the offsite circuit(s) could be completed up to 8 hours prior to entry into the Condition. Performance of this SR before entry into the Condition can be credited to establish the accelerated Frequency and therefore is equivalent to performing the SR within 1 hour after entry into the Condition. The LCO Bases describes the components and features which comprise the offsite circuits. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met.

However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, applies only if the 13.8 kV offsite power circuit is being used to feed 6.9 kV buses 5 and 6 and the UAT is supplying 6.9 kV bus 1, 2, 3 or 4. This action prevents the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 from the UAT to offsite power after a unit trip. Transfer of buses 1, 2, 3, and 4

(continued)

BASES

ACTIONS

A.2 (continued)

from the UAT to offsite power could result in overloading the 13.8 kV/6.9 kV autotransformer. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the alternate offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded by these manual actions. Automatic transfer of buses 1, 2, 3, and 4 can be disabled by placing 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the "pull-out" position.

Although the auto-transfer feature is normally disabled prior to placing the 13.8 kV offsite power circuit in service, a Completion Time of 1 hour ensures that the 13.8 kV circuit meets requirements for Operability promptly when the alternate offsite circuit is configured to support the response of ESF functions.

A.3

Required Action A.3, which only applies if the train will not be powered automatically from an offsite source when the main turbine generator trips, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of redundant required features. Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train.

Therefore, if a required safety feature is supported by an inoperable offsite circuit, then the failure of the DG associated with that required safety feature will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train. However, if a required safety feature is supported by an inoperable offsite circuit and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then the failure of the DG associated with that required safety feature will result in the loss of a safety function. Required Action A.3 ensures that appropriate compensatory measures are taken for a Condition where the loss of a DG could result in the loss of a safety function when an offsite circuit is not OPERABLE.

(continued)

BASES

ACTIONS

A.3 (continued)

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, not required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pump(s) is capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action A.3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. The train will not have offsite power automatically supplying its loads following a trip of the main turbine generator; and

b. A required feature powered from another safeguards power train is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering that offsite power is not automatically available to one train of the onsite Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the two remaining safeguards power trains of the onsite Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion

(continued)

BASES

ACTIONS

A.3 (continued)

Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. For activities that will require entry into the associated Condition, performance of SR 3.8.1.1 for the offsite circuit(s) could be completed up to 8 hours prior to entry into the Condition. Performance of this SR before entry into the Condition can be credited to establish the accelerated Frequency and therefore is equivalent to performing the SR within 1 hour after entry into the Condition. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not

(continued)

BASES

ACTIONS

B.2 (continued)

result in a complete loss of redundant required features. Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train. Therefore, if a required safety feature is supported by an inoperable DG, then the failure of the offsite circuit will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train (and DG). However, if a required safety feature is supported by an inoperable DG and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then a loss of offsite power will result in the loss of a safety function. Required Action B.2 ensures that appropriate compensatory measures are taken for a Condition where the loss of offsite power could result in the loss of a safety function when a DG is not OPERABLE.

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, not required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pumps is capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature powered from another safeguards power train is inoperable.

(continued)

ACTIONS

B.2 (continued)

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with either OPERABLE DG, results in starting the Completion Time for the Required Action. A COMPLETION TIME of four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DGs, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action

(continued)

ACTIONS

B.3.1 and B.3.2 (continued)

program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. Two offsite circuits are inoperable when both the immediate access circuit and the delayed offsite circuit are not available to one or more safeguards power trains. The most probable cause is a failure in a portion of the circuit that is common to both offsite circuits. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.3). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that three complete safeguards power trains are OPERABLE. When a redundant required feature is not OPERABLE, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are included as discussed in the Bases for Required Action A.3. The Completion Time for Required Action C.1 is intended to allow the

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours.

This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

(continued)

ACTIONS

C.1 and C.2 (continued)

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient.

In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours.

If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. When the UAT is being used to supply 6.9 kV buses 1, 2, 3 Or 4 and the 13.8 kV offsite circuit is being used to supply 6.9 kV buses 5 and 6, the autotransfer function is disabled. Therefore, 480 V safeguards buses 2A and 3A (safeguards train 2A/3A) will not be automatically re-energized with offsite power following a plant trip until connected to the offsite circuit by operator action. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no offsite or DG AC power source automatically available to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems – Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train would be de-energized during an event. LCO 3.8.9 provides the appropriate restrictions for a train that would be de-energized.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure.

The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With two or more DGs inoperable, the remaining standby AC sources are not adequate to satisfy analysis assumptions. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1 and H.1

Conditions G and H correspond to a level of degradation in which all redundancy in the AC electrical power supplies has been lost or a loss of safety function has already occurred. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 1). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 8).

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 422 V is the value determined to be acceptable in the analysis of the degraded grid condition. This value allows for voltage drop to the terminals of 480 V motors. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating.

The specified maximum steady state output voltage of 500 V is equal to the maximum operating voltage specified for 480 V circuit

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

breakers. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ±2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The verification includes a sufficient number of breakers in their correct position together with proper bus voltage to ensure that distribution buses and loads are appropriately connected to either their preferred or backup power source for each of the offsite circuits (Normal and Alternate), and that appropriate independence of offsite circuits is maintained. Portions of this SR may require telephone communication with the District Operator or IP2 Control Room personnel capable of confirming the status of the offsite circuits or some breaker positions. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because 6.9 kV bus status and 13.8 kV circuit status are displayed in the control room.

SR 3.8.1.2

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period.

For the purposes of SR 3.8.1.2, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that, at a 31 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 (continued)

assumptions of the design basis LOCA analysis in the FSAR, Chapter 14 (Ref. 5).

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing. DGs have redundant air start motors and both air start motors are actuated by both channels of the start logic. The DG is OPERABLE when either air start motor is OPERABLE; however, this SR will not demonstrate that both of the air start motors are independently capable of starting the DG. If an air start motor is not capable of performing its intended function, a DG is inoperable until a timed start is conducted using the remaining air start motor. Alternately, this SR may be performed using one air start motor (i.e., redundant air start motor isolated) on a staggered basis to ensure that the DG will start with either air start motor.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads of 90% to 100% of the continuous rating. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3 (continued)

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for approximately 1 hour of DG operation at full load.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.5 (continued)

several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 8). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. Therefore, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR is consistent with the 31 day Frequency for verification of DG operability.

SR 3.8.1.7

Transfer of the offsite power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7 (continued)

these components usually pass the SR when performed. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and unit safety systems. ***This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.***

SR 3.8.1.8

Verification that 6.9 kV buses 2 and 3 will auto transfer (fast transfer) from the Unit Auxiliary transformer to 6.9 kV buses 5 and 6 (i.e. station auxiliary transformer) following a loss of voltage on 6.9 kV buses 2 and 3 is needed to confirm the Operability of a function assumed to operate to provide offsite power to safeguards power train 2A/3A following a trip of the main generator.

An actual demonstration of this feature requires the tripping of the main generator while the reactor is at power with the main generator

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8 (continued)

supplying 6.9 kV buses 2 and 3. This will cause perturbations to the electrical distribution systems that could challenge unit safety systems during a plant shutdown. Therefore, 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. The 24 month Frequency is based on engineering judgement taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length.

This SR is modified by two Notes. The reason for Note 1 is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge unit safety systems. ***This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.*** Credit may be taken for unplanned events that satisfy this SR. As stated in Note 2, this SR is only required to be met when the 138 kV offsite circuit is supplying 6.9 kV buses 5 and 6 because, if the 13.8 kV circuit is supplying 6.9 kV buses 5 and 6, then the feature tested by this SR is required to be disabled.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

This Surveillance demonstrates that DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed, low lube oil pressure, and engine overcrank) trip the DG to avert substantial damage to the DG unit. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. ***This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.***

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

IEEE-387-1995 (Ref. 9) 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, ≥ 105 minutes of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor of ≤ 0.~~9~~***85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33***. Th~~is~~***ese*** power factors ~~is~~***were*** chosen to be representative of the actual design basis inductive loading that the DG would experience. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 24 month Frequency is consistent with the recommendations of Ref. 9, and takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by ~~two~~ ***four*** Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. The reason for Note 2 is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and unit safety systems. ***This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following***

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10 (continued)

corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Note 3 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 3 allows the surveillance to be conducted at a power factor other than ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33. These conditions occur when grid voltage is high, and the additional field excitation needed to get the power factor to ≤ 0.85 for EDG 31, ≤ 0.87 for EDG 32, and, ≤ 0.84 for EDG 33 results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to 0.85 for EDG 31, 0.87 for EDG 32, and, 0.84 for EDG 33 while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor of 0.85 for EDG 31, 0.87 for EDG 32, and, 0.84 for EDG 33 may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained close as practicable to 0.85 for EDG 31, 0.87 for EDG 32, and, 0.84 for EDG 33 without exceeding the DG excitation limits. Note 4 recognizes that there is greater difficulty in meeting the power factors while tied to the 13.8 kV offsite power and requires an assessment to ascertain whether the power factors can be reasonably met.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11

Under accident conditions with concurrent loss of offsite power, loads are sequentially connected to the bus by individual load timers to prevent overloading of the DGs due to high motor starting currents. The design load sequence time interval tolerance ensure that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is based on engineering judgment, taking into consideration operating experience that has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that specifies that load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. This note is needed because these time delay relays affect the OPERABILITY of both the AC sources (offsite power and DG) and the specific load that the relay starts. If a timer fails to start a required load or starts the load later than assumed in the analysis, then the required load is not OPERABLE. If a timer starts the load outside the design interval (early or late), then the DG and offsite source are not OPERABLE because overlap of equipment starts may cause an offsite source to exceed limits for voltage or current or a DG to exceed limits for voltage, current or frequency. Therefore, when an individual load sequence timer is not OPERABLE, because the timing sequence is outside the design interval, Condition D must be entered. However, if the automatic initiation capability of the affected load is disabled, Condition D may be exited, and the Actions for the inoperable load are taken. It is conservative to disable the automatic initiation capability of a component rather than continue with the associated DG inoperable because of the following: the potential for adverse impact on the DG by simultaneous start of ESF equipment is eliminated; all other loads powered from the safeguards power train are available to respond to

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11 (continued)

the event; and, the load with the inoperable timer remains available for a manual start after the one minute completion of the normal starting sequence.

SR 3.8.1.12

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. This SR verifies all actions encountered from an ESF signal concurrent with the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated, or residual heat removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation.

In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12 (continued)

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 24 months.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil and temperature maintained and lube oil continuously circulated consistent with manufacturer recommendations for DGs.

The reason for Note 2 is that the performance of the Surveillance would remove required offsite circuits from service, perturb the electrical distribution system, and challenge safety systems. ***This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance: as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown or startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment.***

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12 (continued)

Simultaneous testing of all three safeguards power trains is acceptable as long as the following plant conditions are established:

- All three DGs are available,
- diverse and redundant decay heat removal is available,
- no offsite power circuits are inoperable, and
- no simultaneous activities are performed that are precursors to events requiring AC power for mitigation (e.g., fuel handling accident or inadvertent RCS draindown)

SR 3.8.1.13

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is to allow SR 3.8.1.12 to satisfy the requirements of this SR if SR 3.8.1.12 is performed with more than one safeguards power train concurrently.

REFERENCES

1. 10 CFR 50, Appendix A.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 14.

(continued)

BASES

REFERENCES (continued)

6. Regulatory Guide 1.93, Rev. 0, December 1974.

7. Generic Letter 84-15, Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability.

8. Regulatory Guide 1.137, Rev. 0, 1978.

9. IEEE Standard 387-1995, IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.

10. Calculation SGX-00073-01, Dated February 6, 2004