ENERGY NORTHWEST

P.O. Box 968 ■ Richland, Washington 99352-0968

April 6, 2001
GO2-01-053

Docket No. 50-397

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Gentlemen:

Subject: **COLUMBIA GENERATING STATION OPERATING LICENSE NPF-21 REQUEST FOR TECHNICAL SPECIFICATIONS AMENDMENT TO REMOVE OPERATING MODE RESTRICTIONS FOR EMERGENCY DIESEL GENERATOR SURVEILLANCE TESTING**

References:
1) Letter dated October 2, 2000, Jon B. Hopkins, NRC, to Mike Reandeau, Clinton Power Station, "Clinton Power Station, Unit 1-Issuance of Amendment (TAC No. MA9269)"

2) Letter GI2-01-038 dated March 22, 2001, Jack Cushing, NRC, to JV Parrish, Energy Northwest, "Request for Additional Information For The Columbia Generating Station (TAC NO MB1259)"

3) Letter GO2-01-028 dated February 20, 2001, RL Webring, Energy Northwest to NRC, "Request For Technical Specification Amendment To Remove Operating Mode Restrictions For Emergency Diesel Generator Surveillance Testing"

In accordance with the Code of Federal Regulations, Title 10, Parts 2.101, 50.59 and 50.90, Energy Northwest hereby submits a revised request for amendment to the Columbia Generating Station Technical Specifications (TS) to remove selected operating Mode restrictions for performing emergency diesel generator (DG) testing. In addition, a revision to the TS Bases has been initiated pursuant to the TS Bases Control Program of TS 5.5.10 and 10CFR50.36(a) and is included to assist the staff in its review of the proposed TS change. These pending changes are included for information only and are not considered part of the proposed license amendment.

This revised request incorporates changes, which address NRC requests for additional information (Reference 2), and completely replaces our original submittal (Reference 3).

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The proposed change removes the restriction associated with the following Surveillance Requirements (SRs) that prohibit performing the required testing during Modes 1 and 2.

- SR 3.8.1.9: This SR requires demonstrating that the DG can reject its single largest load without the DG output frequency exceeding a specific limit.
- SR 3.8.1.10: This SR requires demonstrating that the DG can reject its full load without the DG output voltage exceeding a specific limit.
- SR 3.8.1.14: This SR requires starting and then running the DG continuously at or near full-load capability for greater than or equal to 24 hours.

The proposed change also removes the restriction associated with the following SRs that prohibits performing the required testing during Modes 1, 2, and 3.

- SR 3.8.1.13: This SR requires demonstrating that the DG non-emergency (non-critical) automatic trips are bypassed on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal.
- SR 3.8.1.17: This SR requires demonstrating that the DG automatic switchover from the test mode to ready-to-load operation is attained upon receipt of an ECCS initiation signal while maintaining availability of the offsite source.

The proposed change also allows the performance of SR 3.8.1.14 to satisfy SR 3.8.1.3 (monthly one-hour synchronized and loaded DG run) by adding a Note 5 to SR 3.8.1.3 that allows the endurance test of SR 3.8.1.14 to be performed in lieu of load-run test in SR 3.8.1.3.

The requested changes provide operational flexibility to allow the above tests to be performed during Modes 1, 2, and 3 with no significant decrease in operational safety. This will provide flexibility in outage scheduling and reduce outage critical path time since these DG surveillance tests would no longer be required to be performed during Modes 4 or 5. In addition, this change will potentially avoid a plant shutdown if corrective maintenance during power operations results in the need to perform the surveillance. It should be noted that the staff has approved similar changes for a number of other plants with offsite and onsite electrical power source designs similar to Columbia Generating Station. Specifically, similar changes were most recently approved for the Clinton Power Station (Reference 1).

Energy Northwest has determined that these surveillance tests can be performed online without undue risk. When these tests are performed in Modes 1, 2, or 3, the plant will be configured essentially the same as when they are performed in Modes 4 or 5. Additionally, the monthly operability surveillance required by SR 3.8.1.3, which is performed in Modes 1, 2, and 3, results in similar out of service times, for similar reasons, and uses the same AC distribution lineup that will be used to perform the requested surveillance procedures online. A risk assessment in accordance with Regulatory Guide 1.177 has confirmed that the increase in risk is acceptable (see Attachment 1).

Additional information has been attached to this letter to complete the amendment request.

- Attachment 1 describes the background of the request and provides an evaluation of the proposed changes. In addition, this evaluation addresses request for additional information questions posed by the staff during their review of the Clinton Power Station submittal.
- Attachment 2 contains an evaluation of the changes in accordance with 10CFR50.92(c) and concludes they do not result in a significant hazards consideration.
- Attachment 3 provides the Environmental Assessment Applicability Review and notes that the proposed change meets the eligibility criteria for a categorical exclusion as set forth in 10CFR51.22(c)(9). Therefore, in accordance with 10CFR51.22(b), an environmental assessment of the change is not required.
- Attachment 4 provides marked up pages of the TS revision.
- Attachment 5 consists of the typed TS pages as proposed by this amendment.
- Attachment 6 provides marked up pages of the TS Bases revision.
- Attachment 7 provides the response requested for Reference 2.

This request for amendment has been approved by the Columbia Generating Station Plant Operations Committee and reviewed by the Energy Northwest Corporate Nuclear Safety Review Board. In accordance with 10CFR50.91, the State of Washington has been provided a copy of this letter.

Since the proposed changes can provide significant reductions in outage critical path time, Energy Northwest respectfully requests review of this amendment by May 30, 2001. This allows rescheduling of the above SR's outside the R-15 outage scope.

Should you have any questions or desire additional information regarding this matter, please contact me or PJ Inserra at (509) 377-4147.

Respectfully,

W.W. Coleman for
RL Webring
Vice President, Operations Support/PIO
Mail Drop PE08

Attachments, as noted

cc: EW Merschoff - NRC RIV
JS Cushing - NRC NRR
NRC Senior Resident Inspector – 988C
DJ Ross – EFSEC
TC Poindexter - Winston & Strawn
DL Williams - BPA/1399

STATE OF WASHINGTON)
)
COUNTY OF BENTON)

Subject: Request for Amendment To Remove Operating Mode Restrictions For Emergency Diesel Generator Testing

I, DW Coleman, being duly sworn, subscribe to and say that I am the Acting Vice President, Operations Support/PIO, for ENERGY NORTHWEST, the applicant herein; that I have the full authority to execute this oath; that I have reviewed the foregoing; and that to the best of my knowledge, information, and belief that the statements made in it are true.

DATE April 6, 2001

D. W. Coleman
DW Coleman
Acting Vice President, Operations Support/PIO

On this date personally appeared before me DW Colman, to me known to be the individual who executed the foregoing instrument, and acknowledged that he signed the same as his free act and deed for the uses and purposes herein mentioned.

GIVEN under my hand and seal this 6 day of April 2001

JAN WEBER
COMMISSION EXPIRES
NOTARY
PUBLIC
5-18-02
STATE OF WASHINGTON

Jan Weber
Notary Public in and for the
STATE OF WASHINGTON

Residing at Kennewick, WA

My Commission expires 5-18-02

SUMMARY OF PROPOSED TECHNICAL SPECIFICATIONS CHANGE

BACKGROUND

Columbia Generating Station's Technical Specifications (TS) 3.8.1, "AC Sources - Operating," specifies requirements for the Electrical Power Distribution System AC sources. The unit AC Electrical Power Distribution System sources consist of the offsite power sources and the Class 1E onsite standby power sources (diesel generators [DGs] 1, 2, and 3). As required by 10CFR50, Appendix A, GDC 17, 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.

Figure 1 is a simplified one-line diagram of Columbia Generating Station's onsite and offsite distribution system. The Class 1E AC distribution system supplies electrical power to three divisional load groups, Divisions 1, 2, and 3, with each division powered by an independent Class 1E 4.16 kV ESF bus. Divisions 1 and 2, 4.16 kV ESF buses, have two separate and independent offsite sources of power. Division 3, 4.16 kV ESF bus, has one source of offsite power. Each Class 1E 4.16 kV ESF bus has a dedicated onsite DG. Any two of the three divisions of ESF systems provide the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the switchyard from the Bonneville Power Administration (BPA) transmission network. From the switchyard two qualified, electrically and physically separated circuits provide AC power to the Divisions 1 and 2, 4.16 kV ESF buses (SM-7 and SM-8). One qualified circuit provides AC power to the Division 3, 4.16 kV ESF bus (SM-4). One qualified circuit (to all 4.16 kV ESF buses) is powered from the 230 kV Ashe Substation stepped down through the 230 kV/4.16 kV windings of a 230 kV/6.9 kV/4.16 kV transformer (the startup transformer, TR-S). The other qualified circuit (to Divisions 1 and 2, 4.16 kV ESF buses only) is powered from the 115 kV Benton Substation stepped down through a 115 kV /4.16 kV transformer (the backup transformer, TR-B). The offsite AC electrical power sources are designed and located to minimize to the extent practicable the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power network and circuits to the onsite Class 1E 4.16 kV ESF buses is found in the Columbia Generating Station Final Safety Analysis Report, Chapter 8.

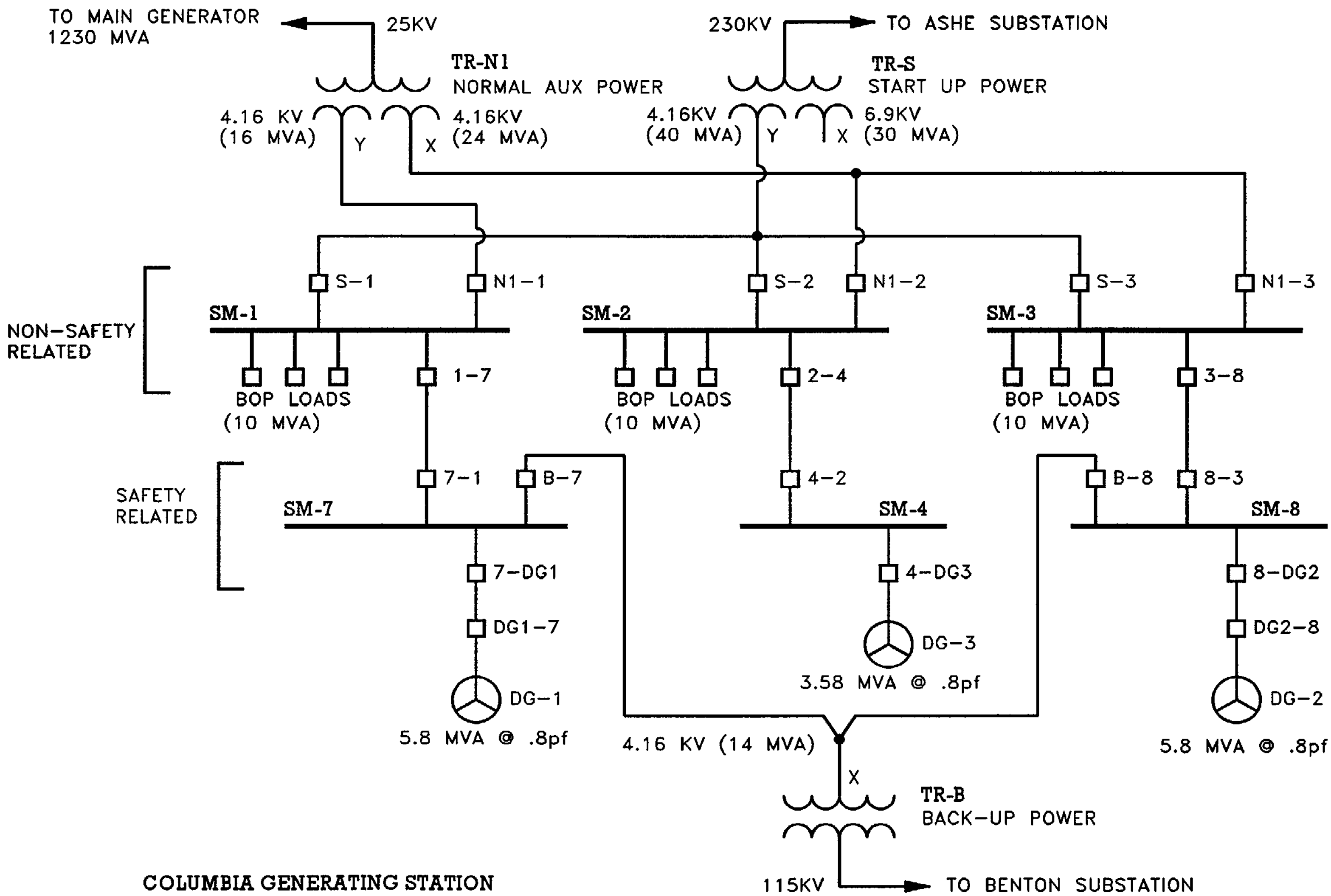
A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

The startup transformer normally provides power to all 4.16 kV ESF buses when the main generator is not connected to the grid. An automatic transfer feature is provided for Divisions 1 and 2 such that if power is lost to a 4.16 kV ESF bus (SM-7 and SM-8) due to a loss of the startup transformer supply, the backup transformer supply breaker to the bus will automatically close and provide power. Manual live transfer capability of power between the startup and backup transformer sources is also provided. When the main generator is tied to the grid, power is provided to all the 4.16 kV ESF buses by a 25 kV/4.16 kV normal auxiliary transformer (TR-N1) fed from the main generator 25 kV isolated phase bus. However, this power source is not allowed to be credited with meeting the requirements of Limiting Condition for Operation (LCO) 3.8.1.a, since it does not come from an offsite circuit. Automatic transfer capability is provided so that failure of the auxiliary transformer supply (from TR-N1) causes immediate tripping of the normal auxiliary transformer supply breakers and simultaneous closing of the startup transformer auxiliary switchgear breakers to supply the balance of plant (BOP) and ESF buses. Each startup transformer supply breaker is interlocked to close only if the associated normal auxiliary transformer supply breaker is not locked out, thus preventing closing onto a fault or connecting a credited source to a non-credited source. Manual live transfer capability of power between the normal auxiliary transformer source and the startup and backup (Divisions 1 and 2 only) transformer sources is also provided.

Following an accident signal, certain required Division 1 and 2 plant loads are started in a predetermined sequence in order to prevent overloading the offsite power startup or backup transformers.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically on loss of coolant accident (LOCA) low reactor water level signal or high drywell pressure signal per LCO 3.3.5.1. The DG also starts on an ESF bus degraded voltage or undervoltage signal per LCO 3.3.8.1. After the DG has started, it automatically ties to its respective ESF bus after loss of all offsite power independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to the ESF bus on a LOCA signal alone.

In the event of a loss of offsite power (LOOP), 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). Certain required plant loads are returned to service or started in a predetermined sequence in order to prevent overloading the DG.



**COLUMBIA GENERATING STATION
SIMPLIFIED ONE LINE**

Figure 1

DESCRIPTION OF PROPOSED CHANGE

Technical Specification LCO 3.8.1 delineates requirements for AC power sources while in Modes 1, 2, and 3. The proposed change would amend the following Surveillance Requirements (SRs) pertaining to the DGs. SR 3.8.1.9 requires demonstrating that the DG can reject its associated single largest post-accident load without the generator frequency exceeding specified limits. SR 3.8.1.10 requires demonstrating that the DG can reject its full load without the DG output voltage exceeding a specified limit. SR 3.8.1.13 requires demonstrating that all DG non-emergency automatic trips are bypassed in response to an ECCS actuation signal. SR 3.8.1.14 requires demonstrating that the DG can start and run at full load for greater than or equal to 24 hours. SR 3.8.1.17 requires demonstrating that with the DG operating in the test mode, the DG is verified to automatically return to a ready-to-load condition in response to an ECCS actuation signal.

SR 3.8.1.9, SR 3.8.1.10, and SR 3.8.1.14 are currently restricted from being performed while the plant is in Modes 1 or 2. A note precedes each of the SRs in the TS, which states in part that the surveillance shall not be performed in Modes 1 or 2. The TS Bases states that the reason for this restriction is to prevent unnecessary perturbations to the electrical distribution systems which could challenge steady state operation and thus plant safety systems if the SR was performed with the reactor in Modes 1 or 2. SR 3.8.1.13 and SR 3.8.1.17 are restricted from being performed in Modes 1, 2, or 3, as a similar note precedes these SRs. The TS Bases for SR 3.8.1.13 states that the reason for the restriction is that performing the surveillance removes a required DG from service. The TS Bases for SR 3.8.1.17 states the reason for the restriction is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

Based on reconsideration of the need and reason for the SR notes, Energy Northwest is proposing to modify the note to remove the Mode 1 and 2 restrictions for performing SR 3.8.1.9, SR 3.8.1.10, and SR 3.8.1.14, and to remove the Mode 1, 2, and 3 restrictions for performing SR 3.8.1.13 and SR 3.8.1.17. The proposed changes will allow performance of the testing required by these SRs during Modes 1 and 2 (or Mode 3) such that the testing will no longer be required to be performed during plant outages. This will help to reduce the complexity of coordinating work and testing activities during refueling outages and could potentially reduce outage critical path time. In addition, this change will potentially avoid a plant shutdown if corrective maintenance during power operations results in the need to perform the surveillance. A note is also proposed to be added to SR 3.8.1.3 to allow the endurance test of SR 3.8.1.14 to be performed in lieu of the load-run test in SR 3.8.1.3 provided the requirements, except the upper load limits, of SR 3.8.1.3 are met. The reason is to avoid having to perform an unnecessary test on the DG.

Specifically, Note 1 for SR 3.8.1.9 and SR 3.8.1.10, and Note 2 for SR 3.8.1.14 currently read as follows: "This surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR." The Notes for SR 3.8.1.13 and 3.8.1.17 are identical except they also include Mode 3. The Note for each of these SRs is proposed to be revised to remove the mode restrictions such that the Note reads as follows: "Credit may be taken for unplanned events that satisfy this SR."

Subsequent to approval of the proposed change, the TS Bases for SR 3.8.1.9, SR 3.8.1.10, and SR 3.8.1.14 will also be revised to remove the sentence that states: "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, as a result, plant safety systems." The TS Bases for SR 3.8.1.13 will be revised to remove the statement; "The reason for the Note is that performing the Surveillance removes a required DG from service." The TS Bases for SR 3.8.1.17 will be revised to remove the sentence that states: "The reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems."

Additionally, the following statement will be added to the TS Bases for SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.14, and SR 3.8.1.17: "Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related and/or non safety-related distribution buses) connected to one offsite source, while the remaining safety-related (and associated non safety-related) distribution buses are aligned to the unit auxiliary transformers (or other offsite source). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations."

The following Note 5 is proposed to be added to SR 3.8.1.3 to allow the performance of SR 3.8.1.14 to be credited for satisfying the requirements of SR 3.8.1.3. "The endurance test of SR 3.8.1.14 may be performed in lieu of the load-run test in SR 3.8.1.3 provided the requirements, except the upper load limits, of SR 3.8.1.3 are met." Correspondingly, the following statement will be added to the TS Bases of SR 3.8.1.3. "Note 5 stipulates that performance of the endurance test of SR 3.8.1.14 can be used to satisfy the requirements of SR 3.8.1.3. The upper load limits of SR 3.8.1.3 may be exceeded provided the remaining requirements of SR 3.8.1.3 are met. The reason for this allowance is to avoid having to perform an unnecessary test on the DG."

The proposed changes to the TS and TS Bases are provided in Attachment 4 and 6 respectively. The proposed TS Bases changes are for your information only and are included to assist the staff in their review of the proposed changes to the TS and will be controlled by TS 5.5.10, "Technical Specifications Bases Control Program."

JUSTIFICATION FOR PROPOSED CHANGES

Although the TS Bases, as currently written, state that the reason for the SR Note (for SRs 3.8.1.9, 3.8.1.10 and 3.8.1.14) is to preclude the potential for perturbations of the electrical distribution system during plant operation, reconsideration of this basis has determined that the noted concern is unwarranted. This conclusion is based on industry and plant experience with the performance of testing required by the affected SRs, realistic consideration of the conditions typically present during performance of the affected testing, and the low probability of a significant electrical system voltage perturbation during such testing. This testing does not significantly impact the DG(s) availability for responding to an accident during the testing. The risk of performing these surveillances during plant operation is not significantly greater than the risk associated with the performance of other TS required DG surveillances that are not prohibited from being performed during plant operation.

Performance of portions of the procedure for these SRs will result in momentary DG inoperability as discussed below, but the DG availability is not significantly affected. SRs 3.8.1.9, 3.8.1.10, 3.8.1.14, and 3.8.1.17 are performed by paralleling the DG in test with offsite power in the same plant configuration as the existing monthly surveillance testing of the DG required by SR 3.8.1.3, which is conducted during power operations. In the event of any occurrence (except ESF bus fault) that would cause DG protective devices to actuate during the performance of these SRs, the DG will either separate from its respective emergency bus, allowing the offsite circuit to continue to supply the bus, or the ESF bus will be separated from the offsite circuit allowing the DG to continue supplying the ESF bus. Further, performance of the required testing at power would not result in the inoperability of any other safety-related equipment or result in a challenge to any plant safety system.

Testing Pursuant to SR 3.8.1.9 and SR 3.8.1.10

The historical approach for performance of the load rejection tests per SRs 3.8.1.9 and 3.8.1.10, is (with the reactor in Modes 4 or 5) to parallel the DG with the offsite source, load the tested DG to the required load, and then open the DG output breaker. Opening of the DG output breaker separates the DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. This evolution has had little impact on the plant electrical distribution system. The power system loading during such testing is within the rating of all transformers, switchgear, and breakers, both before and after the load rejection. As further explained below, performance of the load rejection SRs does not cause any significant perturbations to the electrical distribution systems as the DG is separated from the bus.

During monthly DG surveillance testing required by SR 3.8.1.3, the electric distribution system is aligned so that the tested diesel is paralleled to the 4.16 kV winding of the 40 MVA startup transformer. This is accomplished by transferring an auxiliary switchgear bus (SM-1, 2, or 3) from the normal transformer (TR-N) to the TR-S transformer. This transfer switches the supply of both BOP and Class 1E loads to TR-S for one division. The transferred load is normally between 7 MW and 14 MW. Evaluation of recorded bus voltage during transfer from TR-N to TR-S shows that there is a voltage change experienced by the running loads during the transfer. The incoming 230 kV supply, which is essentially unloaded, is approximately 200 volts above the voltage of the loaded TR-N. Thus, the voltage increases when the manual live transfer from TR-N to the TR-S supply occurs (less than 5%). Likewise, the running loads on the affected bus experience a somewhat smaller decrease in voltage when the manual live transfer from TR-S back to the loaded TR-N occurs. This bus transfer is performed routinely during plant operation at power and shutdown. In comparison, the voltage "switching transients" on the affected bus during performance of these load reject tests are very minor.

For each DG being tested, its safety bus and upstream nonsafety-related distribution system (if aligning to TR-S) are synchronized with the offsite network prior to the load rejection tests. Using Division 1 as an example, load flow calculations show the following conclusions. Before synchronizing the DG, the 4.16 kV winding of the Startup transformer could be loaded to about 16.6 MVA or 41.5% of its rating. This is SM-1 fully loaded for normal plant operation which includes SM-7 loaded up to 6.45 MVA with the Standby Service Water (SW) pump on to support testing. With DG-1 synchronized to the preferred offsite source and loaded to about 1.4 MVA (the largest single load is the equivalent of a SW motor), the load on the 4.16 kV winding of the Startup transformer reduces to about 15.2 MVA. After the DG breaker is tripped, the local source of generation is dropped so the network will accept the safety bus load and continue to establish the voltage at the safety bus and the upstream non safety-related bus. For SR 3.8.1.9, the change in load for a single set of buses connected to the startup transformer with a DG-1 output breaker trip is only about 3.5% of the rating of the startup transformer's 4.16 kV winding (1.4 MVA/40 MVA). For SR 3.8.1.10, the change in load (5 MVA) for a single set of buses connected to the startup transformer with a DG-1 output breaker trip is approximately 12.5% (5.0 MVA/40 MVA). Likewise, conducting these tests with DG-1 synchronized to the Backup offsite source results in a change in load of only 10% (or 1.4 MVA/14 MVA) of the transformer rating for SR 3.8.1.9 and approximately 36% (or 5 MVA/14 MVA) for SR 3.8.1.10. The step load change to the Startup or Backup transformer from these tests are not significant enough to cause challenges to steady state plant operation.

Similarly, when the DG full load reject surveillance test is performed at shutdown, test results show only about a one percent step change (41.6 volts) in bus voltage at the 4160 kV level, with voltage recovery within 1 second, and with no observable voltage transient on the Startup transformer or internal distribution system. The effect at 480-volt and below is expected to be within the same percentage and recovery time. Since manual live bus transfers and large pump starts routinely occur without distribution system transients and the DG breakers are switching loads within system capacity and component ratings, conducting this test online will not produce a significant transient voltage on the connected electrical distribution system.

The small step change in load to the Startup transformer from these tests (due to the DG output breaker opening) is less than the starting MVA for most of the larger motors connected to the nonsafety-related bus (e.g., the 5000HP circulating water pump motor). These motors are routinely started on the Startup transformer during normal plant startup conditions without significant transient voltage on the distribution system. Large motor loads with higher starting MVA than the load reject tests are also started on the Backup transformer during shutdown conditions without significant transient voltage on the distribution system (e.g., the associated DG service water pump motor and the turbine service water pump motor).

The potential for a significant grid disturbance or a sustained low voltage condition to occur on the grid during the timeframe of a load rejection test is very remote. However, if this were to occur, protective relaying is available to protect the DG while it is connected to the grid. Protection for the Class 1E buses is also provided by loss of power instrumentation required to be Operable per LCO 3.3.8.1, "Loss of Power Instrumentation." See "Testing Pursuant to SR 3.8.1.14" for details on this protective instrumentation.

Therefore, performing load reject tests in accordance with SR 3.8.1.9 and SR 3.8.1.10 in Modes 1 or 2 would not cause significant perturbations of the electrical distribution system.

Testing Pursuant to SR 3.8.1.17

The performance of the DG test mode override per SR 3.8.1.17 ensures the availability of the DG for accident conditions is unaffected during the performance of the surveillance test. This test is performed while the DG is paralleled with the offsite source by simulating a LOCA signal to the DG start circuitry. This causes the DG output breaker to open and the DG is returned to a ready-to-load condition. Similar to the tests performed for SRs 3.8.1.9 and 3.8.1.10, opening the DG output breaker separates the DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. Consequently, performance of testing pursuant to SR 3.8.1.17 does not cause any significant perturbations to the electrical distribution systems as the DG is separated from the bus.[1] In addition, similar to testing performed for SRs 3.8.1.9 and 3.8.1.10, the power system loading for this test is well within the rating of the affected transformers, switchgear, and breakers, both before and after the load rejection.

[1] As noted in the TS Bases for this SR, the intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by DG operation in the test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads 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. On this basis, performance of routine testing required pursuant to SR 3.8.1.17 does not require separating the bus from offsite power. Consequently, performance of this surveillance does not require removing an offsite circuit from service, as currently implied in the TS Bases for this SR. Therefore, as noted previously, the TS Bases will be revised accordingly.

Testing Pursuant to SR 3.8.1.13

Performance of testing required per SR 3.8.1.13 in Modes 1, 2, or 3 to verify that non-emergency automatic trips are bypassed on an ECCS initiation signal is justified because this SR is not performed with the DG paralleled to offsite power, and the unavailability of the DG during the conduct of this test is minimal. Following the test, manual action is required by the operator stationed locally for testing to reset the trip used to shutdown the DG so that the DG can be placed in a normal standby lineup. Since the test is conducted with the DG unloaded and isolated from its respective emergency bus, there is no impact to the electrical distribution system. Therefore, there is no mechanism for challenging continued steady state operation and the unavailability time is minimal.

The test is performed by first manually starting the DG. While the DG is at rated speed and voltage, a simulated ECCS initiation (LOCA) signal is input to the DG logic. The DG is not connected to the ESF bus. The non-emergency automatic trips are verified to not trip the DG (i.e., verifying that the associated lockout device is not tripped) by simulating the actuation of the non-emergency trips. The only jumpering and signal simulation required is executed at the relay level in the DG control circuitry such that only the DG being tested is affected.

Testing Pursuant to SR 3.8.1.14

Performance of the 24-hour DG endurance testing per SR 3.8.1.14 in Modes 1 or 2 is justified, in part, by the fact that Columbia Generating Station currently tests its DGs paralleled to offsite power during required monthly surveillance testing while at power. The duration of the tests are approximately two hours and are performed pursuant to monthly surveillance SR 3.8.1.2/SR 3.8.1.3 and the semi-annual surveillance SR 3.8.1.7/SR 3.8.1.3. The intent of the 24-hour endurance run (i.e., to demonstrate the ultimate load carrying capability and endurance of the DG) is met whether the test is conducted with the plant on line or shut down. Protective device reliability is unaffected by this proposed change.

Since the performance of SR 3.8.1.14 essentially envelops the requirements of SR 3.8.1.3, a change to SR 3.8.1.3 is proposed to allow performance of SR 3.8.1.14 to satisfy the requirements of SR 3.8.1.3. The requirements that the endurance test be performed immediately following, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7 would remain. However, that portion of SR 3.8.1.3 that requires maintaining the loading of the DG within specific limits would not be applicable when SR 3.8.1.14 is being used to satisfy the surveillance requirement of SR 3.8.1.3.

Risk management practices, including limitations within the Surveillance procedures, will ensure that this SR will not be scheduled when the potential for grid or bus disturbances exists (such as during heavy grid loading, severe weather conditions, or maintenance activities affecting the bus). Also, when conducting this test during plant operations, the other two DGs, including their support systems, will remain operable and protected during the conduct of the 24-hour run. It is acknowledged that when the DG is paralleled to offsite power, the affected train of the emergency power system is not independent of disturbances on the offsite power system and onsite distribution system and potential interaction with the DG (e.g., a DG trip may result due to overcurrent or reverse power, or a lockout device may be actuated). However, there is actual plant operating experience where large BOP motor loads have been started with a DG running in parallel for the 24-hour endurance run (performed with the plant in shutdown) without deleterious effects to the electrical distribution system or connected station auxiliary loads. Therefore, performance of this SR is not expected to cause perturbations on the electrical distribution system(s) that could challenge steady state operation of the plant.

A concern of DG operation in parallel with offsite power is that a disturbance on or loss of the offsite source could result in the loss or unavailability of a DG (though this loss or unavailability would be temporary if it merely involved resetting the DG lockout device). The DG is protected from faults on the grid and upstream of the safety bus, from faults on the safety bus and close in to the diesel generator, and from generator overload conditions from a loss of offsite power. The diesel generator's overcurrent relay is set to distinguish between faults, overloads, and normal running loads. Because of its transient reactance and decrement characteristic (with a current boost exciter), the diesel generator will contribute approximately 6 per unit momentary and 3 per unit steady state current to a fault. This attribute allows for coordination of protective relays in the distribution system.

For the case of a fault on the grid or a fault upstream of the source breaker to the ESF bus in the non-Class 1E system, the incoming source breaker to the safety bus (CB-7/1, CB-B/7, CB-4/2, CB-8/3, or CB-B/8) is tripped while the DG continues to supply the connected safety bus. For a fault on the safety bus with a DG connected and paralleled to the offsite network, an overcurrent relay on the incoming offsite circuit(s) will sense the fault condition and will trip the source breaker to the bus. Additionally, a trip and lockout of the DG breaker and the other offsite source circuit breaker will occur to protect all sources from closing in on or remaining connected to the faulted bus. For close in faults (defined as faults within the differential overcurrent relay's zone of protection) to the DG cable feeder or to the diesel engine(s) or generator winding itself, protective devices will shutdown the engine(s) and isolate the DG from the safety bus, allowing the offsite circuit the opportunity to continue to supply the safety bus.

Likewise, the DG is protected from overcurrent resulting from the non-Class 1E loads connected to the upstream buses, in the event of a loss of TR-S power. This overcurrent protection provides isolation of the DG and emergency bus from the upstream non-Class 1E loads without disconnecting the DG from the emergency bus. Additionally, the probability of a DG being rendered unavailable due to a grid disturbance coupled with the probability of such a disturbance occurring concurrent with the 24-hour DG endurance testing is quite remote. Protection is also provided to assure that in the remote possibility that the grid disturbance results in a loss of TR-S and a DG trip, primary and secondary undervoltage relays required by LCO 3.3.8.1 automatically transfer the Division 1 and 2 safety buses to TR-B.

Columbia Generating Station's procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities, degraded grid conditions, and paralleling a DG with offsite power. For example, during testing, only one DG is operated in parallel with offsite power at a time. This configuration provides for sufficient isolation of the onsite power sources from offsite power while still enabling testing to demonstrate DG operability. In this configuration, it is only possible for one DG to be affected by an unstable offsite power system. Even then, it may be possible for the locally stationed operator to reset the affected lockout device so that the DG can be restarted. If the unlikely scenario of a coincident LOOP and a DG failure were to occur, the two remaining DGs would still maintain plant safe shutdown capability. Any two of the three divisions of ESF systems provide for the minimum safety functions necessary to shut down and maintain the unit in a safe shutdown condition.

Another concern during parallel operation of the DG with TR-S is that a loss of the offsite source would result in a loss of power to the BOP loads connected to the auxiliary switchgear bus through which the DG is being paralleled. The resulting plant transient would most likely result in a loss of a reactor feedpump and initiate an automatic plant shutdown on low reactor water level. This same potential also exists whenever the monthly DG operability testing is performed. The initiating event frequency of a LOOP occurring during normal monthly DG testing for each DG is 9.89E-05/yr. The performance of these additional surveillances at power uses the same plant configuration as is currently allowed for monthly DG testing. The initiating event frequency of a LOOP occurring during the additional testing time of a DG being paralleled by this change is very low (1.07E-04/yr). This would result in a total initiating event frequency of a LOOP during all at power testing per DG of 2.06E-04/yr. A risk analysis of this additional testing for all DGs is less than the threshold limits of Regulatory Guide 1.177. See below for additional detail.

Consideration of a DG Automatic Start Signal During the DG 24-Hour Endurance Test

a. Loss-of-offsite power
b. Loss of coolant accident safety injection
c. LOOP occurring with a LOCA initiation

a. Loss-of-offsite power. In response to a LOOP during DG testing (i.e., with the DG running and paralleled to the offsite power source via the associated 4.16 kV bus), the DG would attempt to supply power to the loads on the safety-related 4.16 kV bus, the non-Class 1E loads and the loads (or fault) on the grid (assuming the grid remains connected to the bus). Because this loading greatly exceeds the DG capability, bus voltage and frequency would drop significantly. The DG would momentarily respond by raising generator field current via its voltage regulator to support the bus voltage and by increasing the fuel supply to the engine via its governor to support the bus frequency. This response, however, would have a negligible effect on restoring the grid and would eventually lead to an actuation of either the DG voltage-restrained overcurrent relay or the undervoltage relays, as further described below.

In the event of a sustained overcurrent condition initiated by a grid-related LOOP, the DG voltage-restrained overcurrent relays energize an auxiliary relay. This auxiliary relay immediately trips the source breaker from the associated normal auxiliary switchgear (SM 1, 2, or 3) for the respective divisional ESF bus. This separates the safety bus from the associated non-Class 1E loads and the 230 kV grid, thus removing the overcurrent condition and allows the DG to continue to supply the safety bus. If the overcurrent condition does not clear within a short time delay (i.e., the source to the safety bus does not trip), the overcurrent relay trips the DG output breaker. This results in immediate undervoltage of the ESF bus and initiates the transfer sequence to connect the ESF bus to the backup transformer for ESF Divisions 1 and 2. The Division 3 ESF bus would be re-energized by resetting the DG 3 overcurrent relay and lockout device to allow automatic restart of DG 3 to supply the Division 3 ESF loads.

In response to the LOOP actuation signal while the DG is paralleled to the offsite source, the droop control on the DG voltage regulator and the electronic governor will not automatically switch over to the isochronous mode of operation. The 4.16 kV bus frequency remains slightly elevated following the protective logic actuation of source breakers to separate from offsite power because of the manual droop setting on the governor during the 24-hour endurance run. No operator action is required to maintain the safety bus within proper voltage and frequency limits. However, operating procedures ensure that during all diesel generator testing a local operator is available to verify frequency, voltage, and load characteristics (VARS) remain within acceptable ranges.[2]

b. <u>Loss of coolant accident with safety injection.</u> For a LOCA with a safety injection signal initiated while the DG is in the test configuration, the DG test mode is overridden by the LOCA actuation signal. Upon receipt of the LOCA actuation signal, the DG output breaker trips open and TR-S or TR-B continues to supply power to the connected loads. The DG continues to operate at acceptable speed and voltage in a standby ready to load condition and is capable of automatically connecting to its 4.16 kV bus should there be a subsequent LOOP event. This capability is periodically verified by performance of the testing required by SR 3.8.1.17.

As indicated previously, the DG will not automatically switch from the droop to isochronous mode on receipt of LOCA signal.[2] However, the DG is still capable of maintaining proper voltage and frequency limits and accepting the required loads should it be reconnected to the safety bus. Additionally, non-emergency protective trips are bypassed on a LOCA signal to preclude spurious trips of the DG(s).

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[2] The NRC review and approval of the design of the droop setting during testing of the DG was addressed in the NRC Safety Evaluation Report provided in a Letter from RB Samworth, NRR to GC Sorensen, WPPSS, "Standby Diesel Generator Automatic Return to Standby Mode (TAC No. 60955)", dated October 5, 1989.

c. <u>LOOP occurring with a LOCA initiation signal.</u> A LOOP occurring with a LOCA initiation while a DG is in a test mode involves a highly improbable combination of events or conditions. Sequences postulated for such a highly improbable scenario are considered to be beyond the design or licensing basis of the Columbia Generating Station. Notwithstanding, given such an unlikely scenario, Columbia Generating Station's DGs can respond to either a sequence of LOCA then LOOP, simultaneous LOCA/LOOP, or LOOP then LOCA while paralleled with offsite power. The response of a DG to a grid-related LOOP and LOCA while the DG is in test (i.e., paralleled to the offsite power source) is dependent on which of the two events/conditions (LOOP or LOCA) occurs first or whether the two events are assumed to occur simultaneously.

1. For a LOCA occurring while the DG is in test, followed by a grid-related LOOP, the LOCA initiation signal will override the test mode and immediately ensure the DG is brought to a ready-to-load condition, as described previously. The DG will be in a standby running condition with the DG output breaker ready to close onto the bus on demand at proper voltage and frequency. Upon occurrence of the subsequent LOOP (loss of both the TR-S and TR-B), the DG output breaker will close the DG onto the bus, and the associated emergency loads will be sequenced onto the bus via the associated LOCA and LOCA/LOOP delay timers (see Columbia Generating Station Technical Specifications LCO 3.3.5.1).

2. For a LOCA occurring simultaneously with a grid-related LOOP, while the DG is in test, the LOCA initiation signal will override the test mode and open the DG output breaker (to return the DG to a ready-to-load condition). As soon as the DG output breaker permissive logic is satisfied (i.e., the DG is at rated speed and/or voltage, the associated offsite source circuit feed breakers are open, and no voltage is sensed on the bus by the primary loss-of-voltage bus relays), the DG output breaker will close to supply power to the bus, and the associated emergency loads will be sequenced onto the re-energized bus via the associated delay timers as described above.

3. For a postulated event where the grid-related LOOP precedes the LOCA initiation with the DG in test, availability of the DG is still assured. As described earlier, occurrence of the LOOP will cause a significant drop in bus voltage and a large increase in DG output current that results in a trip of the source breaker initially by the voltage-restrained overcurrent relay backed up by the ESF bus undervoltage relays. Tripping the source breaker removes the overload or the effect of the fault from the offsite source and allows the DG to supply power to its safety-related bus. Loss of the 230 kV source also results in loss of power to a number of BOP loads such as a condensate pump, a booster pump, a turbine driven feed pump system equipment, and a circulating water pump that were also being supplied at the time by the 230 kV source. The plant would experience a transient and would most likely result in an automatic plant shutdown on low reactor water level. However, the DG will continue to provide power to the safety bus undisturbed until the receipt of the LOCA signal. For the condition where the grid related LOOP has preceded

the LOCA and the DG is supplying the ESF bus, the LOCA trip of the DG is disabled allowing the DG to continue supplying the ESF bus. The ESF bus ECCS injection pumps are loaded in a planned sequence specifically designed to ensure the loading is within the DG capability.

Evaluation of Unavailability of the DG Due to Testing at Power

Subject to approval of this TS change request, Columbia Generating Station will establish an online testing procedure that minimizes out of service time and efficiently meets the requirements of SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.13, SR 3.8.1.14, and SR 3.8.1.17. However, during certain portions of the procedure the DG will not be able to immediately respond to an accident. This procedure will be comprised of portions of existing procedures that have historically been performed in a shutdown mode with essentially an identical onsite/offsite electrical AC distribution configuration. Those procedures have been performed without resultant electrical distribution system perturbations or offsite power transients.

The proposed TS Amendment will result in small increments of DG unavailability while preparing, aligning, and restoring the DG that will prevent the DG being tested from appropriately responding to an accident. The risk impact, in terms of the change in core damage frequency and a single outage risk (i.e., incremental conditional core damage probability (ICCDP) in RG 1.177), due to unavailability of the DG for surveillance testing at power rather than at shutdown is provided below. Specifically, the times when the DG would not be able to properly respond to a LOCA or LOOP initiation signal are:

For DG1 and DG2:

There is out of service (OOS) time involved with rolling the engine over to ensure there is no water accumulation in the cylinders. For DG1 and DG2 this time averages 0.5 hours each, based upon past monthly operability surveillance tests that perform this operation. This OOS time would actually displace one of the monthly surveillances but will be considered in the total OOS time ICCDP calculation for conservatism.

The unavailability associated with actuating the 86 lockout device following any emergency trips of the DG is the only actual increase in OOS time. For DG1 and DG2 this time would be less than 5 minutes per emergency trip actuation. The emergency trip would be used following the 24-hour endurance run (SR 3.8.1.14), following the DG trip from test mode (SR 3.8.1.17), and following the verification that those required automatic trips are bypassed on receiving an ECCS initiation signal (SR 3.8.1.13). For DG1 and DG2, this would result in four emergency trips per DG (the fourth results from the trip from test mode performed against TR-B). The four associated unavailability times following the emergency trip until the 86 lockout device was reset, which again would be roughly 5 minutes per trip, is expected to be a total of 20 minutes or 0.33-hours.

There is no unavailability associated with DG1 or DG2 during any idle operations for warm up or cool down. There is also no DG unavailability when simulating the ECCS signal associated with performing SR 3.8.1.13. The signal is inserted by installing a jumper across the normally open contact of an ECCS initiating relay to simulate to the DG the receiving of the ECCS signal. The actual actuation of the ECCS relay coil is not performed, however the testing of the ECCS relay coil will continue to be performed during shutdown by SR 3.8.1.12 with adequate overlap. The estimated time for performing SR 3.8.1.13 in the new testing procedure is approximately 30 minutes. During this time, less than 5 minutes of unavailability is estimated to occur due to initiation of an emergency trip and resetting the 86 lockout device (following verification that bypassed trips do not trip the DG).

The expected total unavailability time for DG1 and DG2 during performance of this online surveillance procedure for each DG would be 0.8-hours. This is an increase of 0.33 hours over the current monthly OOS time.

For DG3:

There is OOS time involved with rolling the engine over to ensure there is no water accumulation in the cylinders. For DG3 this time averages 0.75 hours based upon past monthly operability surveillances which perform the same operation. This OOS time would actually displace one of the monthly surveillances but will be considered in the total OOS time in the risk calculation for conservatism.

The unavailability associated with actuating the 86 lockout device following the emergency trips of the DG is the only actual increase in OOS time. For DG3 this time would be less than 5 minutes per emergency trip actuation (see above description of DGs 1 and 2 for additional detail). These trips would be following the 24-hour endurance run, the DG trip from test mode, and following the automatic trip bypass verification. Since DG3 is not aligned with TR-B, a fourth trip test is not required. The total unavailability time following the emergency trips until the 86 lockout device was reset is expected to be a total of 15 minutes or 0.25-hours.

There is unavailability time involved with initially placing DG3 in the maintenance mode and in idle for cool down following completion. This averages 0.5-hours, based upon past monthly operability surveillances which perform the same idle cool down operation of the engine.

The total expected unavailability for DG3 during performance of these five SRs during an online surveillance test would average 1.5-hours. This is an increase of 0.25-hours over the current monthly OOS time.

RISK EVALUATION IN ACCORDANCE WITH REGULATORY GUIDE 1.177

The proposed changes have been reviewed against current regulations, orders, and license conditions and are consistent with the NRC's policy for the use of probabilistic approaches to improve Technical Specifications. The proposed changes meet Regulatory Position 2.1 of Regulatory Guide 1.177 to ensure that current regulations, orders, and license conditions for Columbia Generating Station are met. In addition, the proposed changes do not modify any DG design feature or capability. Thus, compliance with General Design Criteria of Appendix A to 10CFR50 is maintained.

This change is consistent with traditional engineering principles and the defense-in-depth philosophy because it does not propose any different plant configurations or testing alignment that is not currently allowed for other tests. Also, the rejection of loads poses much smaller switching transients on the 230 kV source and TR-S than are currently performed as part of normal operational activities for monthly DG testing online. Likewise, for line up to the 115 kV source and TR-B, the load reject tests will not impose a load on the 115 kV source of significant magnitude. The Divisions 1 and 2 load reject of 4400 kW is approximately 12.5% of the TR-S transformer continuous load rating and 36% of the TR-B transformer continuous load rating. Calculations show that design starting loads (BOP, ECCS, and Service Water pump starts) on the offsite sources are similar to or greater than loads resulting from the load reject tests. The paralleling of a single DG to offsite sources for monthly surveillance is currently considered to be consistent with the defense-in-depth philosophy. Single DG testing restrictions are still maintained.

As demonstrated above, the proposed change does not result in a significant reduction in safety margins. The proposed changes to the Mode requirements for testing DGs do not affect the operability requirements for the DGs and verification of operability will continue to be performed. Continued verification of operability supports the capability of the DGs to perform their required function of providing emergency power to plant equipment that supports or constitutes the fission product barriers. Consequently, the performance of these barriers will not be impacted by implementation of this proposed amendment. In addition, the proposed changes involve no modifications to setpoints or limits established or assumed by the accident analysis. On this and the above basis, no safety margins will be impacted.

PRA Capability and Insights

The risk assessment regarding the DG online testing was performed using the Revision 4.2 of the Columbia Generating Station Levels 1 and 2 Probabilistic Safety Assessment (PSA) and the Individual Plant Examination for External Events (IPEEE). The Revision 4.2 model is a modification of the earlier Revision 3, which incorporates comments from the Boiling Water Reactor Owners Group (BWROG) certification process. Revision 4.2 includes the following features:

- Modified LOOP event tree to include onsite power recovery,
- Adjusted LOOP initiating event frequency,
- Reevaluated flooding analysis,
- Reanalyzed common-cause failure,
- Updated testing/maintenance unavailability using maintenance rule data,
- Updated diesel generator data using plant specific failure data, and
- Updated generic data source using the recent General Electric Boiling Water Reactor database.

The BWROG certification of Revision 3 of the PSA noted the following areas that stand out as particularly strong:

- Initiating Event Analysis,
- Systems Analyses,
- Structural Analysis of Containment, and
- Maintenance and Update Process.

In addition, as stated in the safety evaluation [Docket No. 50-397] from the NRC on April 8, 1997, the following conclusions were made.

1. The [Columbia Generating Station] Individual Plant Examination (IPE) is complete with regard to the information requested by Generic Letter (GL) 88-20.
2. The IPE results are reasonable, given [Columbia Generating Station's] design, operation, and history. As a result, the review concluded that the [Columbia Generating Station] IPE process

is capable of identifying the most likely severe accidents and severe accident vulnerabilities and that the IPE has met the intent of GL 88-20.

The [Columbia Generating Station] PSA peer review certification report [November 1997] and the safety evaluation entitled "Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Individual Plant Examination Washington Public Power Supply System, Nuclear Project No.2, Docket No. 50-397" [April 8, 1997] provide more details on the [Columbia Generating Station] IPE evaluations.

The IPEEE was submitted to the NRC in accordance with Generic Letter (GL) 88-20, Supplement 4 and the NRC provided its Staff Evaluation Report "Review of Columbia Generating Station Individual Plant Examination of External Events Submittal (TAC No. M83695) dated February 26, 2001. The staff conducted a screening review, which examined the IPEEE results for their completeness and reasonableness considering the design and operation of the plant. The staff concluded that the aspects of seismic, fires, high winds, floods, transportation, and other external events were adequately addressed.

PRA Quantitative Results Summary

Based on the unavailability evaluation above and adding margin for uncertainty in the conduct of the new online surveillance procedure, a total unavailable time of 3 hours per year for each DG is chosen, assuming that all proposed tests are performed in the same year. For the average maintenance model, the base core damage frequency (CDF) determined for Columbia Generating Station is 2.25E-05 per year. The base large early release frequency (LERF) is 1.34E-06/yr. The incremental CDF associated with DG1, DG2, and DG3 OOS is calculated using the following equation:

$$ICDF_{OOS} = \left\{\left(CDF_{DG1=1} - CDF_{Base}\right) + \left(CDF_{DG2=1} - CDF_{Base}\right) + \left(CDF_{DG3=1} - CDF_{Base}\right)\right\} * \left\{\frac{T_{OOS}}{8760\,\text{hrs}}\right\}$$

where:

$ICDF_{OOS}$ = Annual average incremental core damage frequency due to unavailable DGs
$CDF_{DG1=1}$ = Core damage frequency with DG1 unavailability set to 1.0
$CDF_{DG2=1}$ = Core damage frequency with DG2 unavailability set to 1.0
$CDF_{DG3=1}$ = Core damage frequency with DG3 unavailability set to 1.0
CDF_{Base} = Base core damage frequency
T_{OOS} = Out-of-service time (unavailable) per DG per year.

By requantifying the Columbia Generating Station PSA models with DG1 unavailability equal to 1.0, the resultant CDF given DG1 unavailable was calculated to be 8.79E-05/yr. In the same way, the CDFs given DG2 and DG3 unavailable were calculated to be 9.03E-05/yr and 7.44E-05/yr, respectively. The out-of-service time was conservatively assumed to be 3-hours for each DG. Substituting these values into the above equation yields {(8.79E-05/yr - 2.25E-05/yr) + (9.03E-05/yr - 2.25E-05/yr) + (7.44E-05/yr - 2.25E-05/yr)} * {3 hrs per yr/ 8760 hrs per yr} = 6.34E-08/yr conservatively assuming all three diesels were tested with the same year. The conditional LERFs for DGs 1, 2, and 3 were 7.98E-08/yr, 5.95E-08/yr, and 1.25E-07/yr, respectively. The corresponding results for an incremental large early release frequency (ILERF) related to 3 hours per year of OOS time per diesel for DGs 1, 2, and 3 were 2.73E-11/yr, 2.04E-11/yr, and 4.28E-11/yr for a total ILERF of 9.05E-11/yr assuming all three diesels were tested in the same year.

Additionally, an evaluation was made on the potential for a loss of offsite source coincident with a loss of DG while paralleled (i.e. assumes both fail while in the paralleled configuration). Each DG was estimated to have 26-hours of operation paralleled to the grid in addition to the existing approximately 24 hours of monthly testing currently being conducted. Included in the risk evaluation was the consideration for the common cause of loss of offsite power coupled with loss of the paralleled DG. The incremental risk associated with the common-cause failure of offsite power source and DG being tested is calculated using the following equation.

$$ICDF_{Com\text{-}Cause} = \left(LCDF_{DG1=1} + LCDF_{DG2=1} + LCDF_{DG3=1}\right) * \left(\frac{1}{LOOP_{FRE}}\right) * \left(IEFRE_{Com\text{-}Cause}\right) * \left(\frac{T_{Parallel}}{8760\,hrs}\right)$$

where:

$ICDF_{Com\text{-}Cause}$ =	Average annual incremental core damage frequency due to common-cause failure
$LCDF_{DG1=1}$ =	CDF resulting from the LOOP initiating event (IE) with DG1 unavailability set to 1.0
$LCDF_{DG2=1}$ =	CDF resulting from the LOOP IE with DG2 unavailability set to 1.0
$LCDF_{DG3=1}$ =	CDF resulting from the LOOP IE with DG3 unavailability set to 1.0
$IEFRE_{Com\text{-}Cause}$ =	The common-cause frequency which disables offsite power source and DG at the same time
$LOOP_{FRE}$ =	LOOP initiating event frequency
$T_{Parallel}$ =	The duration while DG is paralleled to the offsite power source per year.

By requantifying the Columbia Generating Station PSA models, the LOOP CDF with DG1 unavailability set to 1.0 ($LCDF_{DG1=1}$) was calculated to be 7.43E-5/yr. The $LCDF_{DG2=1}$ and $LCDF_{DG3=1}$ were calculated to be 7.66E-5/yr and 5.52E-5/yr, respectively. The plant LOOP IE frequency ($LOOP_{FRE}$) was given as 3.61E-02/yr. $T_{Parallel}$ was estimated to be 26-hours per year as previously mentioned. The common-cause frequency ($IEFRE_{Com\text{-}Cause}$) was estimated to be 2.75E-04/yr, which is based on the plant LOOP annual frequency (3.61E-02/yr) and the plant protective device failure probability (7.62E-03). Using the above equation, the ICDF due to common-cause failure was calculated to be 4.66E-09/yr. The conditional LERFs for DGs 1, 2, and 3 for common-cause were calculated to be 5.67E-10/yr, 4.12E-10/yr, and 9.05E-10/yr, respectively. The corresponding ILERF due to common-cause failure were calculated to be 1.68E-12/yr, 1.22E-12/yr, and 2.69E-12/yr for DG 1, 2, and 3 respectively. The total ILERF for common-cause is 5.59E-12/yr.

Combining OOS time ICDF (6.34E-08/yr) with the ICDF due to common cause failure (4.66E-09/yr), results in a total ICDF of 6.81E-08/yr. Similarly, the result for total ILERF was 9.61E-11/yr (9.05E-11/yr + 5.59E-12/yr). The risk assessment was conducted on a per year basis, hence, the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) can be obtained by multiplying by 1 year. The total ICCDP and ICLERP were 6.81E-08 and 9.61E-11, respectively, which are below the thresholds of 5.0E-07 and 5.0E-08 provided in RG 1.177. Additionally, this ICDF results in a Region III risk significance criteria (very small change in risk) of Regulatory Guide 1.174.

__Evaluation of External Events and Internal Fire__

The impact of this change to our Individual Plant Examination for External Events (seismic) and our internal fire PSA was also assessed.

The seismic qualification of all Class 1E equipment at Columbia Generating Station was reevaluated to the requirements of Regulatory Guide 1.100, 1.92, NUREG-0800, and IEEE-344-1975 as part of the initial licensing of the plant. FSAR Section 3.10 provides the results of that reevaluation and Section 3.10.4.3 provides the Seismic Qualification Review Team conclusion of acceptability. The seismic PSA is consistent with the state-of-the-art PRA methodology described in NUREG-1407. Components were screened at the 0.5g review level earthquake. Walkdowns of the plant were conducted to support the analysis. The mean seismic core damage frequency was estimated to be 2.1E-05/yr. The seismic ICDF was calculated directly from IPEEE seismic event trees with the tested DG unavailable and based on the following initiators: 1) seismic induced loss of offsite power, 2) seismic induced small break LOCA, and 3) seismic induced loss of power distribution. The impact due to seismic was an ICDF of 7.89E-8/yr. While a significant seismic event would be expected to generate a loss of offsite power, the online testing of a DG does not affect the seismic capacity of any equipment seismically qualified at Columbia Generating Station. The conclusions of the seismic IPEEE would be unaffected by the implementation of the proposed changes.

A semi-quantitative approach was used to determine the impact of the proposed changes on CDF due to internal fire. The fire CCDF, assuming DG unavailable, was calculated by using the fire dominant cutsets with the DG unavailability set equal to 1.0. The impact due to internal fire was calculated by multiplying the CCDF by the fraction of DG out of service time (3 hr/8760 hr), which results in an ICDF of 7.06E-8/yr for all three DGs (IPEEE internal fire base CDF is 5.5E-05/yr). The conclusions of the internal fire PSA would be unaffected by the implementation of the proposed changes.

Evaluation of high winds, external floods, and other external events in the IPEEE per GL 88-20 were submitted to and reviewed by the NRC. The Staff Evaluation Report concluded that Columbia Generating Station IPEEE is capable of identifying the most likely severe accidents and severe accident vulnerabilities and, the IPEEE has met the intent of Supplement 4 to GL 88-20. The IPEEE determined that the recurrence frequency for the maximum tornado wind speed is approximately 1E-07/yr and, as such, maximum wind speed is eliminated as a plant hazard per the Standard Review Plan. Other external events (e.g., external flooding and others) are considered to be insignificant contributors to severe accidents. The proposed changes have negligible effect on the risk profiles from other external events.

Since the conservative risk evaluation of the external events IPEEE (seismic) and the internal fire PSA yields very small values, the results from the Level 1 and Level 2 PRA provide sufficient insight to the change in risk associated with DG online testing.

Sensitivity Analysis

A sensitivity analysis was performed using the Level 1 PRA by increasing the DG protective device failure probability of 7.62E-03 to 1.0E-01. Likewise, another sensitivity analysis using the Level 1 PRA was also performed by increasing the plant grid-related LOOP frequency of 2.72E-03/yr to the upper bound value of NUREG-1032 of 1.80E-02/yr. The results of the first sensitivity analysis show that minimal impact to the common cause CDF occurs when the DG protective device failure probability was significantly increased as the overall ICDF increased over the base CDF by only 1.25E-07 per year. The second sensitivity analysis results also indicate that minimal impact occurs to the OOS CDF and common cause CDF as the ICDF increased over the base CDF by only 1.08E-07 per year. The ICDF of each sensitively analysis when converted to ICCDP show adequate margin still remains within the Regulatory Guide 1.177 threshold of 5.0E-07 per year in both cases.

The following table summarizes the results of the above discussion.

	ICDF (3 hrs OOS) (per year)	ICDF (26 hrs Paralleled Time) (per year)	ILERF (3 hrs OOS) (per year)	ILERF (26 hrs Paralleled Time) (per year)	Sensitivity DG Protective Device (per year)	Sensitivity LOOP Initiation Frequency (per year)
DG-1	2.24E-08	1.68E-09	2.73E-11	1.68E-12		
DG-2	2.32E-08	1.73E-09	2.04E-11	1.22E-12		
DG-3	1.78E-08	1.25E-09	4.28E-11	2.69E-12		
Sum	6.34E-08	4.66E-09	9.05E-11	5.59E-12		
Total	**6.81E-08**		**9.61E-11**		**1.25E-07**	**1.08E-07**
Total Incremental Core Damage Frequency = 6.81E-08 per year						
Total Incremental Large Early Release Frequency= 9.61E-11 per year						
See above discussion on risk significance of External Events (Seismic) and Internal Fire evaluation and results.						

__**Avoidance of Risk Significant Plant Configurations**__

Columbia Generating Station TS requirements and maintenance rule configuration risk management program ensure configuration risk avoidance.

- The TS impose requirements/restrictions on the required equipment and features associated with the redundant division (i.e., the division(s) associated with the DG(s) not under test) when a DG is inoperable (including being made inoperable for testing or maintenance). Specifically, when a diesel generator becomes inoperable in Modes 1, 2, or 3, Required Action B.2 of TS 3.8.1, "AC Sources - Operating," requires identification of inoperable required features that are redundant to required features supported by the inoperable diesel generator. This Required Action is applicable throughout the entire period of diesel inoperability. Inoperable features on the redundant division can then cause entry into other or more severe Required Actions, thus providing further incentive not to allow a DG to be inoperable whenever a required feature(s) on the redundant division(s) is inoperable. Required Action B.2 is intended to provide assurance that the occurrence of LOOP, during the period that a DG is inoperable, does not result in a complete loss of the safety function of critical systems.

The Safety Function Determination Program (SFDP) pursuant to TS 5.5.11 is used to ensure that there is no loss of a safety function as a result of removing equipment from service for maintenance or testing, with regard to the relationship between support and supported systems or functions as addressed by LCO 3.0.6.

- Online Risk Assessment is performed per PPM 1.5.14 "Risk Assessment and Management For Maintenance/Surveillance Activities" which implements our program to comply with 10CFR50.65a(4). Notwithstanding the requirements of the TS, online scheduling and coordination of work activities at Columbia Generating Station are controlled by strict compliance to plant procedures. Columbia Generating Station procedures (PPM 1.3.1, Section 4.7) require conservative decision making as an integral part of planning, scheduling, and conducting maintenance and surveillance activities during all operational plant modes. A requirement of the risk assessment process prior to performing the DG surveillances on line is that when a DG is planned to be removed from service, no other risk significant components will be scheduled to undergo maintenance or testing activities during the planned DG surveillance duration.

A description of the process, procedures, limitations, reviews and qualitative analysis to be used to perform the DG surveillance testing at power are:

1. In accordance with plant procedure SWP-MAI-01 and MI-3.6.2 "Online Maintenance Work Process," the online maintenance work process begins eleven weeks prior to scheduled maintenance and includes multiple reviews and assessments. Key reviews include: Operations (Senior Reactor Operator), Maintenance, Engineering, and Health Physics personnel at a minimum. Specific responsibility is assigned to assess impact on the plant and regulatory requirements. These reviews include protecting redundant divisions, risk impact assessment, assessing controls and expediting work duration for the Voluntary Entry Into Technical Specification Action Statement (VET), and additional management control related to infrequently performed tests and plant impact.

2. Plant Procedures Manual (PPM) 1.16.6B, "Voluntary Entry Into Technical Specification Action Statements, Licensee Controlled Specifications requirements for operability, or removal of risk Significant SSC's to perform work activities during power operations," establishes controls prior to voluntarily entering Technical Specification Action Statements for the conduct of maintenance and or surveillance testing. The purpose of this procedure is to assess and justify overall plant safety conditions as a result of a VET. This procedure interfaces with and utilizes PPM 1.5.14, "Risk Assessment and Management for Maintenance and Surveillance Activities," to quantify the risk associated with a planned VET.

3. PPM 1.5.14 institutes the risk assessment during the planning, scheduling, and implementation of maintenance and surveillances. The purpose of this procedure is to implement the (a)(4) Section of the amended Maintenance Rule (10CFR50.65). Increasing levels of management review and concurrence, as well as requirements for contingency plan development, are procedurally directed as the risks associated with the VET increase.

Per this procedure, Columbia Generating Station will not voluntarily plan/schedule evolutions that result in either an "orange" condition per the ORAM/SENTINEL (OSP) risk assessment program without a specific contingency plan and the Operations Manager's approval. For a "red" condition, the Plant General Manager's approval is required. Red and orange conditions in the OSP identify conditions of increased risk based on CDF calculations. As a result of the PSA assessment, no maintenance or testing of SSC's dependent on the remaining DGs will be permitted.

Another facet of PPM 1.5.14 addresses the potential for increased risk to plant maintenance and surveillance evolutions as a result of external events or other extreme conditions. Anticipation of such external events or conditions allows the Shift Manager to qualitatively assess the risk to the plant; and to develop appropriate contingency plans. As an example, Columbia Generating Station procedures require communications with the Bonneville Power Administration whenever diesel generator surveillance testing specifies paralleling a diesel generator with offsite power. These communications allow for verification of grid stability and conditions prior to the testing. They also support delay or deferral of testing if appropriate grid conditions are not present. Energy Northwest will enhance procedural requirements to request the BPA to promptly notify Columbia Generating Station if the offsite source stability conditions significantly deteriorate during the period of performing the 24-hour endurance testing. In addition, procedural guidance will be put in place to access regional weather conditions (using the National Weather Service forecast data) forecasted to occur during the 24-hour endurance test. Unanticipated extreme weather conditions (i.e., high winds, lightning, and icing) will be assessed by Operations using developed contingency plans which could result in delay of the scheduled test or discontinuing of an ongoing test.

4. The divisional safety systems not affected by the inoperable diesel generator are placed in "protected" status by control room supervision whenever a diesel generator is inoperable. The protected status ensures that equipment important to maintaining acceptable risk levels and safety functions are not removed from service during the time a DG is inoperable or is paralleled with offsite sources. In addition, a comprehensive plant walkdown will be implemented using existing procedure controls per PPM 1.9.13 to ensure that no maintenance activities are in progress in the transformer yard prior to the start of and during the 24-hour endurance run. Moreover, procedures will be enhanced to ensure internal electrical distribution systems, including switchgear buses and diesel rooms, are properly configured for the test and that maintenance activities in these areas are restricted.

5. The new DG online testing procedures will include restrictions on performing the 24-hour endurance run when adverse weather conditions that could impact the offsite power supply are present or forecasted to occur during the testing period.

These procedures and enhancements form the foundation for our approach to conservative risk-informed decision making at Columbia Generating Station, and ensure the safe and effective planning, scheduling, and implementation of maintenance and surveillance activities at the station.

The initial performance of the new online DG testing procedures will be conducted under a procedure for new or infrequently preformed evolutions. This procedure includes, pre-job briefings for operations and maintenance crews involved in the activity, heightened station awareness, a test coordinator, and management oversight. Energy Northwest has determined that these surveillance tests can be performed online without undue risk.

EVALUATION OF SIGNIFICANT HAZARDS CONSIDERATIONS

SUMMARY OF PROPOSED CHANGE

The proposed change removes the restriction associated with the following Columbia Generating Station Surveillance Requirements (SR) that prohibits performing the required testing during Modes 1 and 2.

- SR 3.8.1.9: This SR requires demonstrating that the DG can reject its single largest load without the DG output frequency exceeding a specific limit.
- SR 3.8.1.10: This SR requires demonstrating that the DG can reject its full load without the DG output voltage exceeding a specific limit.
- SR 3.8.1.14: This SR requires starting and then running the DG continuously at or near full-load capability for greater than or equal to 24 hours.

The proposed change also removes the restriction associated with the following SRs that prohibits performing the required testing during Modes 1, 2, and 3.

- SR 3.8.1.13: This SR requires demonstrating that the DG non-emergency (non-critical) automatic trips are bypassed on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal.
- SR 3.8.1.17: This SR requires demonstrating that the DG automatic switchover from the test mode to ready-to-load operation is attained upon receipt of an ECCS initiation signal (while maintaining availability of the offsite source).

The proposed change also allows the performance of SR 3.8.1.14 to satisfy SR 3.8.1.3 by adding a statement to Note 2 of SR 3.8.1.3 that removes the upper loading limit requirements when credit is taken by the performance of SR 3.8.1.14.

The requested changes provide operational flexibility to allow the above tests to be performed during Modes 1, 2, or 3, as appropriate.

NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

Energy Northwest has evaluated the proposed change to the TS using the criteria established in 10CFR50.92© and has determined that it does not represent a significant hazards consideration as described below:

- **The operation of Columbia Generating Station in accordance with the proposed amendment will not involve a significant increase in the probability or consequences of an accident previously evaluated.**

  The DGs and their associated emergency loads are accident mitigating features, not accident initiating equipment. Therefore, there will be no significant impact on any accident probabilities by the approval of the requested amendment.

  The design of plant equipment is not being modified by these proposed changes. As such, the ability of the DGs to respond to a design basis accident will not be adversely impacted by these proposed changes. The proposed changes do not result in a plant configuration change for performance of the additional testing different from that currently allowed by the Technical Specifications. In addition, experience and further evaluation of the probability of a DG being rendered inoperable concurrent with or due to a significant grid disturbance support the conclusion that the proposed changes do not involve any significant increase in the likelihood of a loss of safety bus. Therefore, there would be no significant impact on any accident consequences.

  Based on the above, the proposed change to permit certain DG surveillance tests to be performed during plant operation will not involve a significant increase of accident probabilities or consequences.

- **The operation of Columbia Generating Station in accordance with the proposed amendment will not create the possibility of a new or different kind of accident from any accident previously evaluated.**

  No new accidents would be created since no changes are being made to the plant that would introduce any new accident causal mechanisms. Equipment will be operated in the same configuration currently allowed by other DG SRs that allow testing in plant Modes 1, 2, and 3. An interaction between the DG under test and the offsite power system that could lead to a consequential loss of safety bus during a grid disturbance is not deemed to be credible. This amendment request does not impact any plant systems that are accident initiators; neither does it adversely impact any accident mitigating systems.

  Based on the above, implementation of the proposed changes will not create the possibility of a new or different kind of accident from any accident previously evaluated.

- **The operation of Columbia Generating Station in accordance with the proposed amendment will not involve a significant reduction in the margin of safety.**

  Margin of safety is related to the confidence in the ability of the fission product barriers to perform their design functions during and following an accident. These barriers include the fuel cladding, the reactor coolant system, and the containment system. The proposed changes to the testing requirements for the plant DGs do not affect the operability requirements for the DGs, as verification of such operability will continue to be performed as required (except during different allowed Modes). Continued verification of operability supports the capability of the DGs to perform their required function of providing emergency power to plant equipment that supports or constitutes the fission product barriers. Consequently, the performance of these fission product barriers will not be impacted by implementation of this proposed amendment.

  In addition, the proposed changes involve no changes to setpoints or limits established or assumed by the accident analysis. On this and the above basis, no safety margins will be impacted. Therefore, implementation of the proposed changes would not involve a significant reduction in a margin of safety.

  Based upon the above analysis, the proposed change will not significantly increase the probability or consequences of any accident previously evaluated, create the possibility of a new or different kind of accident from any accident previously evaluated, or involve a significant reduction in the margin of safety. Therefore, the proposed change meets the requirements of 10CFR50.92© in that it involves no significant hazards consideration.

ENVIRONMENTAL CONSIDERATION

Energy Northwest has evaluated the proposed amendment against the criteria for identification of licensing and regulatory actions requiring environmental assessment in accordance with 10CFR51.21.

Energy Northwest has reviewed this request and determined that the proposed amendment meets the eligibility criteria for categorical exclusion set forth in 10CFR Section 51.22©(9). Pursuant to 10CFR Section 51.22(b), no environmental impact statement or environmental assessment needs to be prepared in connection with the issuance of the amendment. The change meets the eligibility criteria for categorical exclusion set forth in 10CFR Section 51.22(c)(9) for the following reasons:

1) this request does not involve a significant hazards consideration,

2) this request does not involve an increase in the amounts, or a change in the types, of any effluent that may be released offsite, and

3) this request does not involve an increase in individual or cumulative occupational exposure.

REQUEST FOR TECHNICAL SPECIFICATIONS AMENDMENT TO REMOVE OPERATING MODE RESTRICTIONS FOR EMERGENCY DIESEL GENERATOR SURVEILLANCE TESTING
Attachment 5

REPLACEMENT PAGES FOR TECHNICAL SPECIFICATIONS

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.1.3	-------------------NOTES------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by, and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7. 5. The endurance test of SR 3.8.1.14 may be performed in lieu of the load-run test in SR 3.8.1.3 provided the requirements, expect the upper load limits, of SR 3.8.1.3 are met. --- Verify each required DG is synchronized and loaded and operates for $\geq$ 60 minutes at a load $\geq$ 4000 kW and $\leq$ 4400 kW for DG-1 and DG-2, and $\geq$ 2340 kW and $\leq$ 2600 kW for DG-3.	31 days
SR 3.8.1.4	Verify each required day tank contains $\geq$ 1400 gal of fuel oil.	31 days
SR 3.8.1.5	Check for and remove accumulated water from each required day tank.	31 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify each required fuel oil transfer subsystem operates to automatically transfer fuel oil from the storage tank to the day tank.	92 days
SR 3.8.1.7	------------------NOTE------------------ All DG starts may be preceded by an engine prelube period. -- Verify each required DG starts from standby condition and achieves: a. For DG-1 and DG-2 in $\leq$ 15 seconds, voltage $\geq$ 3910 V and frequency $\geq$ 58.8 Hz, and after steady state conditions are reached, maintains voltage $\geq$ 3910 V and $\leq$ 4400 V and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz; and b. For DG-3, in $\leq$ 15 seconds, voltage $\geq$ 3740 V and frequency $\geq$ 58.8 Hz, and after steady state conditions are reached, maintains voltage $\geq$ 3740 V and $\leq$ 4400 V and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz.	184 days
SR 3.8.1.8	------------------NOTE------------------ The automatic transfer function of this Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. -- Verify automatic and manual transfer of the power supply to safety related buses from the startup offsite circuit to the backup offsite circuit.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. Credit may be taken for unplanned events that satisfy this SR. 2. If performed with the DG synchronized with offsite power, it shall be performed at a power factor as close to the power factor of the single largest post-accident load as practicable. -------------------- Verify each required DG rejects a load greater than or equal to its associated single largest post-accident load, and following load rejection, the frequency is ≤ 66.75 Hz.	24 months
SR 3.8.1.10	----------NOTES---------- 1. Credit may be taken for unplanned events that satisfy this SR. 2. If performed with the DG synchronized with offsite power, it shall be performed at the accident load power factor, or at a power factor as close to the accident load power factor as practicable with the field excitation current ≥ 90% of the continuous rating. -------------------- Verify each required DG does not trip and voltage is maintained ≤ 4784 V during and following a load rejection of a load ≥ 4400 kW for DG-1 and DG-2 and ≥ 2600 kW for DG-3.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$ 15 seconds for DG-1 and DG-2, and in $\leq$ 18 seconds for DG-3, 2. energizes auto-connected shutdown loads, 3. maintains steady state voltage $\geq$ 3740 V and $\leq$ 4400 V, 4. maintains steady state frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for $\geq$ 5 minutes.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. --- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each required DG auto-starts from standby condition and: a. For DG-1 and DG-2, in ≤ 15 seconds achieves voltage ≥ 3910 V, and after steady state conditions are reached, maintains voltage ≥ 3910 V and ≤ 4400 V and, for DG-3, in ≤ 15 seconds achieves voltage ≥ 3740 V, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4400 V; b. In ≤ 15 seconds, achieves frequency ≥ 58.8 Hz and after steady state conditions are achieved, maintains frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are auto-connected to the offsite power system.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	------------------NOTE------------------ Credit may be taken for unplanned events that satisfy this SR. -------------------------------------- Verify each required DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except: a. Engine overspeed; b. Generator differential current; and c. Incomplete starting sequence.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	------------------NOTES------------------ 1. Momentary transients outside the load, excitation current, and power factor ranges do not invalidate this test. 2. Credit may be taken for unplanned events that satisfy this SR. 3. If performed with the DG synchronized with offsite power, it shall be performed at the accident load power factor, or at a power factor as close to the accident load power factor as practicable with the field excitation current ≥ 90% of the continuous rating. --- Verify each required DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 4650 kW for DG-1 and DG-2, and ≥ 2850 kW for DG-3; and b. For the remaining hours of the test loaded ≥ 4400 kW for DG-1 and DG-2, and ≥ 2600 kW for DG-3.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	------------------NOTES------------------ 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 1 hour loaded ≥ 4000 kW for DG-1 and DG-2, and ≥ 2340 kW for DG-3. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. --- Verify each required DG starts and achieves: a. For DG-1 and DG-2, in ≤ 15 seconds, voltage ≥ 3910 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 3910 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and b. For DG-3, in ≤ 15 seconds, voltage ≥ 3740 V and frequency ≥ 58.8 Hz, and after steady state conditions are reached, maintains voltage ≥ 3740 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	------------------NOTE------------------ This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. -- Verify each required DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	24 months
SR 3.8.1.17	------------------NOTE------------------ Credit may be taken for unplanned events that satisfy this SR. -- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	24 months

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.18	-----NOTE----- This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify interval between each sequenced load block is within ± 10% of design interval for each time delay relay.	24 months
SR 3.8.1.19	-----NOTES----- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for DG-1 and DG-2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$ 15 seconds, 2. energizes auto-connected emergency loads, 3. maintains steady state voltage $\geq$ 3740 V and $\leq$ 4400 V,	24 months

(continued)

REQUEST FOR TECHNICAL SPECIFICATIONS AMENDMENT TO REMOVE OPERATING MODE RESTRICTIONS FOR EMERGENCY DIESEL GENERATOR SURVEILLANCE TESTING
Attachment 6

MARKED-UP VERSION OF TECHNICAL SPECIFICATIONS BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

Note 5 stipulates that performance of the endurance test of SR 3.8.1.14 can be used to satisfy the requirements of SR 3.8.1.3. The upper load limits of SR 3.8.1.3 may be exceeded provided the remaining requirements of SR 3.8.1.3 are met. The reason for this allowance is to avoid having to perform an unnecessary test on the DG.

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 the low level alarm is annunciated. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%. For DGs 1 and 2, the required fuel oil level supports approximately 3.5 hours of operation at 110% of the continuous rated load. For DG-3, the required fuel oil level supports approximately 7 hours of operation at continuous rated load. The amount above the minimum 1 hour requirement helps to support the 7 day fuel oil supply.

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 in 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 several sources, including condensation, 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 Frequency is established by Regulatory

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

setpoint, or 115% of nominal speed, whichever is lower. For all the DGs, this corresponds to 66.75 Hz, which is the nominal speed plus 75% of the difference between nominal speed and the overspeed trip setpoint.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related and/or non safety-related distribution buses) connected to one offsite source, while the remaining safety-related (and associated non safety-related) distribution buses are aligned to the unit auxiliary transformers (or other offsite source). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

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

This SR has been 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 continued steady state operation and, as a result, plant safety systems.~~ credit may be taken for unplanned events that satisfy this SR. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed at a power factor as close to the power factor of the single largest post-accident load as practicable. The power factor limit is $\leq$ 0.92 for DG-1, $\leq$ 0.86 for DG-2, and $\leq$ 0.92 for DG-3. These power factors are representative of the actual single largest inductive load that the DGs could experience when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 580 kVAR for DG-1, 760 kVAR for DG-2, and 1015 kVAR for DG-3. However, if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the power factor should be maintained as close to the limit as practicable.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

Consistent with Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.8, this Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed at a power factor as close to the accident load power factor as practicable. The power factor limit is $\leq$ 0.89 for DG-1, $\leq$ 0.88 for DG-2, and $\leq$ 0.91 for DG-3. These power factors are representative of the actual design basis inductive loading that the DGs could experience when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related and/or non safety-related distribution buses) connected to one offsite source, while the remaining safety-related (and associated non safety-related) distribution buses are aligned to the unit auxiliary transformers (or other offsite source). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

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

This SR has been modified by two Notes. The reason for Note 1 is that ~~during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.~~ credit may be taken for unplanned events that satisfy this SR. Note 2 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

Consistent with Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.12, this Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation test signal and critical protective functions (engine overspeed, generator differential current, and incomplete starting sequence) trip the DG to avert substantial damage to the DG unit. The non-critical 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 plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

The SR is modified by a Note. The reason for the Note is that ~~performing the Surveillance removes a required DG from service.~~ credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.14

Consistent with Regulatory Guide 1.9 (Ref. 12), paragraph C.2.2.9, this Surveillance requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, 22 hours of which is at a load equivalent to 90% to 100% of the continuous rating of the DG and 2 hours of which is at a load equivalent to 105% to 110% of 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 prelube 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.14 (continued)

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 at a power factor as close to the accident load power factor as practicable. The power factor limit is ≤ 0.89 for DG-1, ≤ 0.88 for DG-2, and ≤ 0.91 for DG-3. These power factors are representative of the actual design basis inductive loading that the DGs could experience when running isolated from offsite power. To meet these power factor limits, the DGs must be loaded to the following reactive values when the SR is performed; 2165 kVAR for DG-1, 2085 kVAR for DG-2, and 1150 kVAR for DG-3.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related and/or non safety-related distribution buses) connected to one offsite source, while the remaining safety-related (and associated non safety-related) distribution buses are aligned to the unit auxiliary transformers (or other offsite source). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

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

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. 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. Similarly, momentary transients of excitation current or power factor do 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 would challenge continued steady state operation and, as a result, plant safety systems.~~ credit may be taken for unplanned events that satisfy this SR. Note 3 is provided in recognition that if the offsite electrical power distribution system voltage is high, increased excitation will be necessary for the DG to match system voltage when synchronizing to the associated ESF bus. Once tied to the ESF bus, it may not be possible to increase DG excitation sufficiently to meet the required reactive load value that ensures the power factor limit is met, without exceeding the DG excitation system ratings. Therefore, to ensure the DG is not placed in an unsafe condition during this test, the power factor limit does not have to be met if grid voltage does not permit the power factor limit to be met when the DG is tied to the grid. When this occurs, the reactive load may be reduced

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

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

This SR has been modified by a Note. The reason for the Note is that ~~performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.~~ credit may be taken for unplanned events that satisfy this SR.

Testing performed for this SR is normally conducted with the DG being tested (and the associated safety-related and/or non safety-related distribution buses) connected to one offsite source, while the remaining safety-related (and associated non safety-related) distribution buses are aligned to the unit auxiliary transformers (or other offsite source). This minimizes the possibility of common cause failures resulting from offsite/grid voltage perturbations.

SR 3.8.1.18

Under accident conditions, loads are sequentially connected to the bus by the automatic load sequence time delay relays. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the DGs due to high motor starting currents. The 10% load sequence time interval tolerance ensures that a sufficient time interval 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. Since only DG-1 and DG-2 have more than one load block, this SR is only applicable to these DGs.

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

This SR is modified by a Note. The reason for the Note is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Credit may be taken for unplanned events that satisfy this SR.

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REQUEST FOR ADDITIONAL INFORMATION EMERGENCY DIESEL GENERATOR SURVEILLANCE TESTING

Question 1. Explain the discrepancies between the incremental core damage frequency (ICDF) definitions in your submittal and the definition of incremental conditional core damage probability (ICCDP) in footnote 2, on page 8, of Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications."

Response: Since the ICCDF was determined on a per year basis, the ICCDP is numerically the same value. Dimensions were corrected to clarify the relationship to Regulatory Guide (RG) 1.177. See Attachment 1, page 21.

Question 2. Provide an annual average value of delta core damage frequency assuming a total unavailability time of 3 hours per year for each diesel generator.

Response: The delta CDF ($ICDF_{OOS}$) is 6.34E-08. See Attachment 1, page 20 and 23.

Question 3. As discussed on page 16 of RG 1.177 (key component 4) discuss the impact of external events, chiefly fire and seismic, on your probabilistic risk assessment results.

Response: The results of the external events (seismic) and internal fire PSA evaluation have been included. See Attachment 1, page 21.

Question 4. Discuss what considerations should be given to not performing the 24-hour load run test when offsite grid condition or configuration is degraded or when adverse or extreme weather conditions (i.e., high winds, lightning, icing) are expected. Discuss the ability to accurately forecast weather conditions that are expected to occur during this test. Discuss what, if any, contingency plans should be developed to restore the inoperable EDG in the event of unanticipated adverse weather or degraded grid conditions occurring which can significantly increase the probability of losing offsite electric power.

Response: Additional detail has been provided on not performing the 24-hour endurance test when offsite grid conditions or configuration is degraded or extreme weather conditions are expected. Weather forecasting through the National Weather Service will be used to determine forecasted adverse or extreme conditions prior to and during the planned testing. Operations will use developed contingency plans to delay or interrupt the online testing should unanticipated conditions occur. See Attachment 1, page 25.

REQUEST FOR ADDITIONAL INFORMATION EMERGENCY DIESEL GENERATOR SURVEILLANCE TESTING (Continued)

Question 5. What would be the worst-case voltage transient on the medium and low-voltage safety buses and the recovery time as a result of a full-loads rejection?

Response: The worst-case voltage recorded during full load rejection testing has been approximately 1% at the medium voltage level. The recovery time was less than 1 second. The effect at 480 volt and below levels in the AC distribution system is expected to be approximately the same percentage. See Attachment, 1 page 8.

Question 6. Provide the duration of SR 3.8.1.13.

Response: The duration of SR 3.8.1.13 when performed by the new online testing procedure is estimated to be no more than 30 minutes. However, the out of service time of the DG will only be during the time between the emergency trip and its reset, which is conservatively estimated to be 5 minutes. See Attachment 1, page 16.

Question 7. Does the licensee's Work Control Programs and Risk Management Programs and procedures cover a comprehensive walkdown just prior to entering this period of reduced equipment availability (EDG testing on-line)?

Response: No. However, we will enhance existing controls to PPM 1.3.19 "Transformer Access and Controls" to assure that no maintenance activities are in progress prior to or during the 24-hour endurance testing. The 24-hour endurance test will be designated as a special test that requires the transformer yard to be off limits to any maintenance activities. Additionally, we will implement procedural requirements to perform a transformer yard, critical switchgear, and DG areas walkdown prior to starting the 24-hour endurance testing. See Attachment 1, page 25.

Question 8. Attachment one, Page 12, first paragraph, last sentence, discusses Division 1 and 2 buses. Provide clarification for Division 3 bus.

Response: Clarification on the Division 3 bus response to loss of the 230 kV offsite source has been added to this amendment request. See Attachment 1 page 13.

Question 9 TS Bases for SR 3.8.1.13 is missing.

Response: The requested TS Bases page has been added to this submittal for information only.