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

Clinton Power Station, Unit 1
Facility Operating License No. NPF-62
NRC Docket No. 50-461

Subject: License Amendment Request to Remove Operating Mode Restrictions for Performing Division 3 AC Sources Surveillance Testing

In accordance with 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," Exelon Generation Company, LLC (EGC) requests an amendment to Facility Operating License No. NPF-62 for Clinton Power Station, Unit 1 (CPS). The proposed amendment would modify CPS Technical Specifications (TS) Section 3.8.1, "AC Sources – Operating," by revising certain Surveillance Requirements (SR) related to the Division 3 AC Sources. The Division 3 AC Sources are independent sources of offsite and onsite alternating current (AC) power primarily dedicated to the High Pressure Core Spray (HPCS) system. The TS currently prohibit performing the testing required by SR 3.8.1.8 and SR 3.8.1.12 in Modes 1 or 2, and prohibit performing the testing required by SR 3.8.1.11, SR 3.8.1.16, and SR 3.8.1.19 in Modes 1, 2, or 3. The proposed amendment would remove these Mode restrictions and allow all five of the identified SRs to be performed in any operating Mode for the Division 3 AC Sources.

This request is subdivided as follows:

- Attachment 1 provides a description of the proposed changes.
- Attachment 2 provides electrical drawings including protective relaying and their associated setpoints for the Division 3 electrical distribution system.
- Attachment 3 provides the relationship between current and time for the Division 3 overcurrent relays.
- Attachment 4 provides the existing CPS TS pages marked up to show the proposed changes.
- Attachment 5 provides the existing CPS TS Bases pages marked up to show the proposed changes. The TS Bases pages are provided for information only and do not require NRC approval.

The proposed change has been reviewed by the CPS Plant Operations Review Committee and approved by the Nuclear Safety Review Board in accordance with the requirements of the EGC Quality Assurance Program.

EGC requests approval of the proposed amendment by October 22, 2011, in order to support upcoming outage planning activities. Once approved, the amendment shall be implemented within 60 days.

There are no new regulatory commitments established by this letter or any of the attachments.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), EGC is notifying the State of Illinois of this application for license amendment by transmitting a copy of this letter and its attachments to the designated State Official.

Should you have any questions concerning this letter, please contact Mitchel Mathews at (630) 657-2819.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 28th day of October, 2010.

Respectfully,

Jeffrey L. Hansen
Manager – Licensing and Regulatory Affairs

Attachments:

1. Evaluation of Proposed Changes
2. Clinton Power Station Electrical Single Line Diagrams and Relay Settings Tables
3. Plot of the Clinton Power Station Division 3 Overcurrent Relay Settings (Amps versus Time)
4. Markup of Existing Technical Specifications Pages
5. Markup of Existing Technical Specifications Bases Pages (For Information Only)

Subject: License Amendment Request to Remove Operating Mode Restrictions for Performing Division 3 AC Sources Surveillance Testing

1.0 SUMMARY DESCRIPTION

This evaluation supports a request to amend Facility Operating License NPF-62 for Clinton Power Station, Unit 1 (CPS).

The proposed changes would revise the Operating License to modify the CPS Technical Specifications (TS) Section 3.8.1, "AC Sources - Operating," by revising certain Surveillance Requirements (SRs) pertaining to the Division 3 AC Sources. The Division 3 AC Sources are independent sources of offsite and onsite alternating current (AC) power primarily dedicated to the High Pressure Core Spray (HPCS) system. The TS currently prohibit performing the testing required by SR 3.8.1.8 and SR 3.8.1.12 in Modes 1 or 2, and prohibit performing the testing required by SR 3.8.1.11, SR 3.8.1.16, and SR 3.8.1.19 in Modes 1, 2, or 3. The proposed amendment removes these Mode restrictions and allows all five of the identified SRs to be performed in any operating Mode for the Division 3 AC Sources only.

As discussed in the TS Bases for each of these SRs, the Mode restrictions for performance of these SRs online were put into place because it was believed that performance of these SRs online would:

1. Perturb the electrical distribution system,
2. Challenge plant safety systems, and/or
3. Remove a required offsite circuit from service.

Sections 3.1 through 3.5 contain a detailed evaluation of these concerns for the online performance of these five SRs for Division 3. This evaluation determined that the performance of these SRs online for Division 3 is acceptable. This is due to the fact that the design of the CPS AC Sources does not present any challenge that would result in a perturbation of the electrical distribution system during the online performance of any of these SRs for Division 3. Additionally, the Division 3 safety system, HPCS, is declared inoperable during the performance of SRs 3.8.1.11, 3.8.1.16, and 3.8.1.19, and the remaining two divisions of safety systems remain unchallenged during the performance of all five of these SRs. Moreover, the brief removal of the required offsite circuit for the performance of SRs 3.8.1.11, 3.8.1.16, and 3.8.1.19, impacts Division 3 AC Sources only. As discussed in the Note to the Applicability requirements for TS 3.8.1, if the HPCS system is not Operable, the Division 3 AC electrical power sources are not required to be OPERABLE. Discussions related to the acceptability performing each of the five SRs listed above online for the Division 3 AC Sources can be found in Section 3.6.

One-line electrical drawings, including protective relaying and their associated setpoints for the Division 3 electrical distribution system, are included as Attachment 2. The purpose of this attachment is to aid in the understanding of the protective relaying scheme for the Division 3 AC Sources at CPS. Additionally, a plot of the CPS Division 3 overcurrent relay settings (i.e., amps versus time) are included as Attachment 3 to further aid in understanding of the CPS Division 3 protective relaying.

The proposed changes will provide greater flexibility in scheduling Division 3 AC Sources activities by allowing the testing to be performed during non-outage times. Having a completely tested Division 3 emergency diesel generator (DG) available for the duration of a refueling outage will reduce the number of system re-alignments and operator workload during an outage. Additionally, performing Division 3 AC Sources activities online increases the Division 3 DG and HPCS system availability during refueling outages and allows the testing of the Division 3 systems to be conducted when both Division 1 and 2 systems are required to be OPERABLE.

2.0 DETAILED DESCRIPTION

2.1 Description of the Proposed Changes

The proposed amendment includes the following revisions to TS Section 3.8.1:

SR 3.8.1.8: Revise Note 2 to remove the restriction that prohibits performance of the SR in Modes 1 or 2, for Division 3 AC sources only. This SR requires verification of the automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.

SR 3.8.1.11: Revise Note 2 to remove the restriction that prohibits performance of the SR in Modes 1, 2, or 3, for the Division 3 DG only. This SR requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated Loss of Offsite Power (LOOP) signal, energizes permanently connected loads in ≤ 12 seconds, achieves and maintains the required voltage and frequency, and supplies permanently connected loads for ≥ 5 minutes.

SR 3.8.1.12: Revise Note 2 to remove the restriction that prohibits performance of the SR in Modes 1 or 2, for the Division 3 DG only. This SR requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated ECCS initiation signal, achieves the required voltage and frequency within the specified time, and operates for ≥ 5 minutes.

SR 3.8.1.16: Revise the Note to remove the restriction that prohibits performance of the SR in Modes 1, 2, or 3, for the Division 3 DG only. This SR requires verification that the Division 3 DG can be synchronized with the offsite power source while loaded with emergency loads, and upon a simulated restoration of offsite power, all loads are transferred to offsite power and the DG returns to ready-to-load operation.

SR 3.8.1.19: Revise Note 2 to remove the restriction that prohibits performance of the SR in Modes 1, 2, or 3, for the Division 3 DG only. This SR requires verification that: the Division 3 DG automatically starts from the standby condition on an actual or simulated LOOP signal in conjunction with an actual or simulated ECCS initiation signal, achieves the required voltage and frequency, and supplies permanently connected loads for ≥ 5 minutes.

Attachment 4 provides markups of the existing TS pages to show the proposed changes. Mark-ups of the current TS Bases pages are provided in Attachment 5 for information only and do not require NRC approval. The TS Bases changes will be processed in accordance with the CPS TS Bases Control Program (i.e., TS Section 5.5.11).

2.2 Background

CPS Technical Specifications (TS) Section 3.8.1, "AC Sources -Operating," specifies requirements for the Electrical Power Distribution System AC Sources. The Class 1E AC Electrical Power Distribution System AC sources at CPS consist of the offsite power sources and the onsite standby power sources, (i.e., Diesel Generators (DGs) 1A, 1B, and 1C). DGs 1A, 1B, and 1C are also referred to as the Division 1 DG, the Division 2 DG, and the Division 3 DG, respectively. As required by 10 CFR 50, Appendix A, GDC 17, "Electric power systems," the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system at CPS supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 4.16 kV ESF bus. Each ESF bus is capable of being supplied by either of two separate and independent offsite sources of power. Each ESF bus also has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to the CPS switchyard from the transmission network. As shown in Figure 1 below, the unit auxiliary transformers (UATs) normally supply power to the non-safety related loads using the main generator as a power source. The secondary source of unit auxiliary AC power is the three reserve auxiliary transformers (RATs) (i.e., RAT A, RAT B, and RAT C). Each RAT is rated at 33.3 MVA. RAT A feeds the 6.9 kV switchgear buses and is sized to carry the startup and running load of the unit from these buses. RAT B feeds the 4.16 kV Class 1E Buses 1A1, 1B1, and 1C1 along with 4.16 kV non-Class 1E Bus 1A, and is sized to carry the startup and running loads for these buses as well as the total coincidental LOCA load for the unit. RAT C feeds the 4.16 kV non-Class 1E Bus 1B and is sized to carry the startup and running load of this bus. All three RATs are connected to the 345 kV switchyard through individual high side disconnects by a common overhead transmission line. Alternatively, an electrically and physically independent 138 kV power source can provide AC power to each of the 4.16 kV ESF buses 1A1, 1B1, and 1C1 via the emergency reserve auxiliary transformer (ERAT). The ERAT is normally energized, but unloaded during at-power operations and is rated to carry 30 MVA.

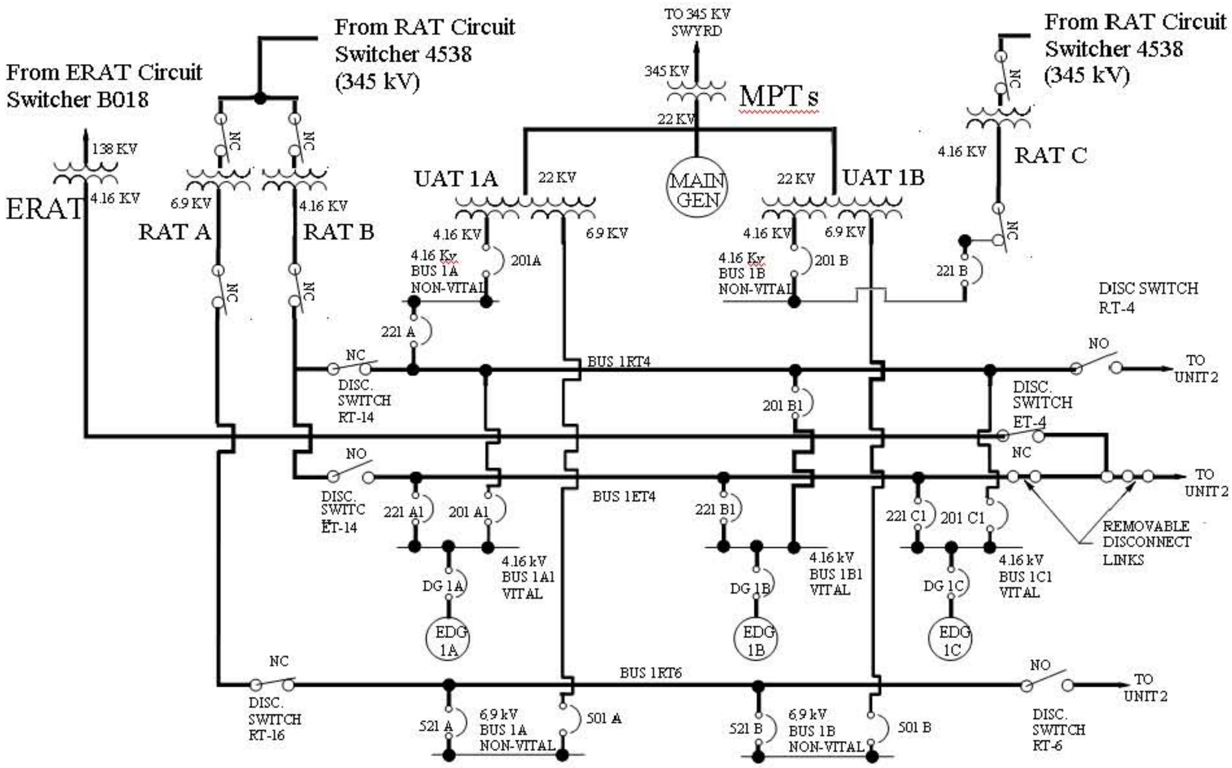


Figure 1: Simplified Drawing of the CPS AC Power Distribution System

The offsite AC electrical power sources are designed and located to minimize 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 ESF buses is found in Updated Safety Analysis Report (USAR), Chapter 8.

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es). A permanently installed static VAR compensator (SVC) is also available onsite and is normally connected to each offsite circuit to support required voltage for the ESF buses.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. A DG starts automatically upon receipt of a loss of coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or an ESF bus degraded voltage or undervoltage signal.

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 such as a LOCA. Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. The Division 3 DG does not have any auto-connected loads.

These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot and DG in standby with engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillances, (e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode).

The AC Sources in one division must be separate and independent to the extent possible of the AC Sources in the other division(s). For the DGs, the separation and independence are complete. For the offsite AC Sources, the separation and independence are to the extent practical since each power source can provide AC power to each of the 4.16 kV ESF buses 1A1, 1B1, and 1C1. A circuit may be connected to more than one ESF bus, with fast transfer capability to the other circuit Operable, and not violate separation criteria.

The Division 3 (i.e., HPCS) power system loads consist of the HPCS pump motor and associated 480 VAC auxiliaries such as motor operated valves, shutdown service water (SX) pump C, and miscellaneous diesel engine auxiliary loads. In addition, the Division 3 DG supplies power to the Division 3 Nuclear System Protection System (NSPS) inverter. This inverter is the normal power supply for Division 3 Reactor Protection System (RPS) instrumentation and Division 3 Source Range Monitor (SRM). The Division 3, HPCS power system is self-contained except for access to both sources of offsite power, directly by connection through the plant AC power distribution system, and for the system initiation signal source. It is operable as an isolated system independent of the electrical connection to any other system by use of the Division 3 diesel generator. Standby auxiliary equipment such as heaters, air compressor, cooling water pumps and battery charger are supplied from the same power source as the HPCS pump motor. The diesel generator is compatible with power available from the plant AC power system.

The Division 3 diesel generator (i.e., DG 1C) has the capability to restore onsite power quickly to the HPCS pump motor in the event offsite power is unavailable, and to provide all power for startup and operation of the HPCS system. The Division 3 diesel generator will start automatically on signal from the plant protection system or HPCS supply bus undervoltage, and when both plant offsite sources are not available, will be automatically connected to the HPCS bus. An automatic start signal overrides the test mode.

The General Electric HPCS system power supply unit Licensing Topical Report, NEDO-10905, gives the starting and accelerating characteristics of the diesel generator set with the various loads in the proper sequence. Although the voltage and frequency characteristics do not meet NRC Regulatory Guide 1.9, "Application and Testing of Safety-Related Diesel Generators in Nuclear Power Plants," justification for this is given because of the unique requirements of the system. The Division 3 diesel generator is unique in that its load is composed predominantly of one large motor whose horsepower is approximately the same as the diesel-engine. The analytical results from a digital dynamics stability program, and prototype tests performed, demonstrate the capability of the diesel-generator and of the equipment associated with the system to meet all necessary requirements. The NRC has previously accepted this analysis which is contained in the NEDO-10905 document.

All safety related continuous duty motors have the ability to deliver their rated horsepower continuously without damage when the voltage at the terminals is 10% above or below rated voltage with rated frequency. These motors can also deliver their full load torque without damage when the voltage at the terminal drops to 75% for infrequent one-minute intervals.

The starting sequence provides for containing Division 3 diesel generator voltage drops down to 62% of rated voltage. This dip in voltage lasts for 1 second and would recover to 75% volts after this time frame. This time frame is short enough to prevent the loss of flux to the field. Therefore, no motor damage or malfunction will occur and the present supply to the motor is adequate.

The Division 3 diesel generator is capable of starting the HPCS motor within the required time in accordance with NEDO-10905 although voltage and frequency drop will exceed the limits specified in NRC Regulatory Guide 1.9.

In addition and as stated in CPS Updated Safety Analysis Report (USAR) Subsection 8.3.1.2.2, the Division 3 diesel generator design includes override capability to ensure automatic switchover from the test mode to ready-to-load operation upon receipt of a LOCA initiation signal consistent with the requirements of IEEE 308 and 387. However, the Division 3 diesel generator is equipped with a mechanical governor that operates only in a droop mode. Normally, the droop setting is set to zero, but during testing (i.e., while the diesel generator is in the test mode) a non-zero droop setting is utilized to support paralleling the diesel generator with the offsite power source. Under such conditions, the droop may be set such that, if a LOCA initiation signal were received concurrent with no offsite power available to the Division 3 bus, operator action may be required to reset the governor and thus ensure bus frequency is within required limits when the diesel generator alone is supplying power to the bus.

The droop mode, as described above, is utilized only during testing. Procedural guidance is given to the main control room operator to adjust engine speed if required in order to restore bus frequency to within the required range. In addition, a dedicated operator is assigned to reset the governor in the event of a LOCA concurrent with a LOOP during testing evolutions. As discussed in CPS USAR Section 8.3.1.1.2.1, a risk assessment performed for the LOCA concurrent with a LOOP demonstrates that the risk associated with this system configuration is very small. Additionally, this condition is not unique to the testing proposed in this request. This condition exists any time the Division 3 DG is operated in test mode and in parallel with offsite sources such as during monthly Division 3 DG testing in accordance with SR 3.8.1.2 or SR 3.8.1.3. On this basis, the Division 3 diesel generator design, with respect to automatic switchover capability from the test mode to ready-to-load operation, has been determined to be acceptable.

Mechanical safety trips recommended by the Division 3 diesel generator vendor and the electrical protective tripping scheme are consistent with the Division 1 and 2 diesel generator tripping schemes and meet the requirements of Regulatory Guide 1.9. All trips except overspeed and generator differential are bypassed on a LOCA.

In this way, the diesel generator availability is fully assured during an offsite power loss.

The HPCS power system is capable of performing its function when subjected to the effects of design basis natural phenomena. In particular, it is classified as Class 1E and Seismic Category I and is housed in a Seismic Category I structure.

The HPCS power system has its own fuel day tank and storage tank with sufficient capacity to operate the standby power source while supplying maximum post-accident HPCS power requirements for a time sufficient to put the plant in a safe condition. Tank size is consistent with availability of backup fuel sources.

A Class 1E DC power supply system provides the HPCS system DC power requirements for control and protection.

As discussed in USAR Section 6.3, the HPCS system is designed and constructed to allow all active components to be tested during normal plant operations. The system has full-flow test lines to and from the suppression pool and the Reactor Core Isolation Cooling (RCIC) storage tank. Additionally, the HPCS pump is provided with a minimum flow bypass line, which discharges to the suppression pool. The valve in this minimum flow bypass line (i.e., 1E22-F012) automatically opens to prevent pump damage due to overheating when other discharge line valves are closed. When suction is taken from the RCIC storage tank or the suppression pool, the minimum flowpath from the HPCS pump discharge is routed to the suppression pool. The 1E22-F012 minimum flow valve automatically opens when HPCS pump discharge pressure increases above 145 psig, and discharge flow is less than 625 gpm. These features allow system testing without discharging into the reactor vessel and, along with the design of the electrical distribution system, facilitate safe performance of Division 3 AC Sources testing pursuant to the subject SRs while in any operational mode.

The HPCS system can be tested at full flow with RCIC storage tank water at any time during plant operation except when the reactor vessel water level is low, or when the water level in the RCIC storage tank is low, or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCS is being tested, the system returns automatically to the operating mode. The two motor-operated valves in the test line to the RCIC storage system are interlocked closed when the suction valve from the suppression pool is open.

A design flow functional test of the HPCS system is performed by pumping water from the RCIC storage tank and back through the full flow test return line to the RCIC storage tank.

3.0 TECHNICAL EVALUATION

3.1 General Basis

Although the TS Bases, as currently written, state that the reasons for the SR Notes imposing Mode restrictions is to preclude the potential for perturbations of the electrical distribution system during plant operation, challenge to plant safety systems, and removal of a required offsite circuit from service, reconsideration of these bases for the Division 3 AC Sources has determined that the noted concerns are not warranted with respect to requiring the affected SRs to be performed only during shutdown conditions. This conclusion is based on: (1) the CPS AC power system design and associated protection features; (2) plant experience with the performance of testing required in accordance with the affected SRs; (3) administrative controls that minimize plant risks during performance of the affected testing; and (4) the low probability of a significant voltage perturbation during such testing. A detailed discussion of this analysis is contained in Sections 3.2 through 3.5.

For each of the independent offsite circuits at CPS, a permanently installed static VAR compensator (SVC) is provided which is normally connected to the secondary side of the associated auxiliary power transformer (e.g., RAT B or ERAT) via two in-series circuit breakers. The ERAT SVC and RAT B SVC provide steady state, dynamic, and transient voltage support to ensure that the Class 1E loads will operate as required during anticipated or postulated events. However, as noted in the Bases for LCO 3.8.1, SVC support of the offsite power sources may not be required at all times, depending on prevailing grid conditions relative to the requirements of the facility. The internal control system for each SVC includes control and protective functions. However, backup protection is provided by a fully redundant and independent protection system, consisting of two redundant subsystems for each SVC, for fail-safe performance of the overall SVC system. Operability of these redundant protection subsystems is addressed by LCO 3.8.11. The redundant protection subsystems are powered from independent DC supplies. Each subsystem activates separate and independent relays, which in turn will automatically open the two main SVC circuit breakers to automatically disconnect the SVC from the 4.16 kV circuit in response to various SVC failure conditions. The SVC main circuit breakers are redundant for increased protection against breaker failure. The SVCs ensure that minor transmission network voltage instabilities do not impact the voltage support for the associated Class 1E loads. However, if the voltage did begin to degrade with a DG operating in parallel with the ERAT or RAT B, the associated SVC would attempt to raise voltage until it reached 28.5 MVar, and then the DG voltage regulator would increase field current in an effort to raise terminal voltage until the voltage regulator reached its limit.

CPS declares the Division 3 DG inoperable during the subject surveillance testing due to the DG governor speed droop being set at its midpoint during the test. Additionally, the Division 3 DG and its associated loads are unavailable for responding to an accident during portions of the testing. The effect on safety of performing the subject SRs for the Division 3 DG during plant operation is not significantly different than the effect on safety associated with the performance of other DG surveillances required by the TS that are not prohibited from being performed during plant operation. For example, SR 3.8.1.16, is performed by paralleling the DG in test with offsite power, similar to the existing monthly run of the DG (i.e., to meet SRs 3.8.1.2 and 3.8.1.3), which is conducted with the plant online. Furthermore, performance of the required testing online does not challenge the Division 1 and Division 2 safety systems since the combined LOCA loading of all three 4.16 kV buses is well within the capabilities of the ERAT and RAT B and the Division 1 and Division 2 safety systems remain isolated from the power sources undergoing testing.

Additionally, performance of the testing online as proposed will not impact the RCIC system, which provides a function similar to the HPCS system as discussed in TS 3.5.3, "RCIC System." The RCIC pump consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the reactor head cooling spray nozzle. Since the RCIC steam turbine drives the RCIC pump, and none of the RCIC support equipment is powered from Division 3, the RCIC system will not be impacted by online testing of the Division 3 AC Sources.

Finally, testing in the proposed manner does not interfere with normal plant operation.

3.2 Transient Analysis

Degraded Voltage

Prior to commencing testing, CPS procedures require verification that both offsite power sources are in a condition that supports testing. This verification includes confirmation that both SVCs are operable and the 345 kV ring bus is intact prior to initiating the test. If any of the above conditions are not met before or during the testing, the test will be terminated.

With the 4.16 kV buses in a normal testing alignment as discussed above, and the Division 3 DG operating in parallel with offsite via RAT B, a degraded voltage condition could not occur, since RAT B is powered from the 345 kV switchyard. With the ring bus intact, the normal operating band for the CPS main generator output (i.e., 359 kV-362 kV as specified in CPS procedure 3005.01, "Unit Power Changes," Section 8.1.19) will maintain grid voltage well above degraded voltage values. Testing would be terminated if the ring bus was opened or normal operating parameters on the main generator could not be maintained.

To enter into a degraded voltage condition while performing testing with the Division 3 DG operating in parallel with offsite via the ERAT, extreme conditions would have to exist. The ERAT SVC would have to be at its maximum output of 28.5 MVar and the 138 kV system would have to be below the Real Time Contingency Analysis (RTCA) monitoring value. The reliability coordinator and balancing authority and transmission operator (i.e., MISO and AmerenIP, respectively) continuously monitor the 138 kV and 345 kV systems and alert CPS of degrading grid conditions. The degraded voltage alarm setpoints at CPS were chosen such that CPS is notified before reaching the degraded voltage relay setpoint. If the voltage began to degrade and went unnoticed, the SVC output would increase until it reached 28.5 MVar and the Division 3 DG voltage regulator would increase field current in an effort to raise terminal voltage until the regulator reached its limit. The DG would continue to operate normally with the voltage regulator at maximum output. The frequency would remain within limits and there would be no significant change in the loading on the diesel. This condition would have no impact on the DG or associated loads. If this condition did occur, the second level undervoltage relays would pickup as soon as the DG output breaker is opened, because the DG would no longer be providing reactive power to support system voltage. The Division 3, 4.16 kV bus would then automatically transfer back to the Division 3 DG after the degraded voltage relay time delay expires.

Since CPS has SVCs supporting both offsite sources, the conditions necessary for CPS to enter into a degraded voltage condition on the 4.16 kV buses in any operational configuration would be severe to the extent that all AC Sources testing would be terminated.

In summary, based on the administrative controls regarding the availability and quality of offsite power sources found in CPS procedures, design of the CPS offsite power systems, the design of the Division 3 electrical power distribution system protective relaying, and the support of 4.16 kV bus voltage provided by the CPS SVCs, there is no additional adverse condition introduced by testing in the proposed manner.

Loss of Offsite Power (LOOP)

A significant overload of the Division 3 DG could result if operating in parallel with an offsite source that experiences a loss of power. A substantial number of variables must be considered when analyzing scenarios with the Division 3 DG operating in parallel with an offsite source should a LOOP occur. Multiple line-ups, initial loading, and the vast number of potential LOOP scenarios make it difficult to analyze for each possibility. However, there are only three potential outcomes of concern.

These outcomes are:

1) The diesel is loaded within its capability,
2) The diesel is loaded at or near its full fuel rack position, and
3) The diesel is loaded beyond its full fuel rack position.

Each of these outcomes is discussed in detail below.

First, if the Division 3 DG is loaded within its capability, it will continue operate with no adverse consequences.

Secondly, prolonged operation at or near the Division 3 DG fuel rack limit could result in turbo-charger damage due to over-temperature and over-speed. There is no specific guidance on how long this condition must exist before damage occurs. However, according to the vendor for CPS DGs, operating at the Division 3 DG full fuel rack limit for 15 minutes without experiencing damage is reasonable and operation in this condition for up to 30 minutes may be possible. This guidance is based on industry experience including non-nuclear operating experience. This experience has shown that the majority of turbo-charger damage that has been experienced occurred during operation at the DG full fuel rack limit in marine applications, typically poorly maintained tug boats. It should be noted that loading conditions at or near the fuel rack limit would be unlikely. The most likely DG overload scenarios involve transient loading within the Division 3 DG's capability or in excess of its capability. Industry experience also indicates that there is sufficient time for manual operator action to terminate the test and prevent turbo-charger damage in this scenario.

Lastly, significant overloading beyond the Division 3 DG capability would begin to stall the DG. At that point, multiple protective relay actuation sequences would begin. Many variables must be considered, and it is difficult to accurately determine which device would actuate first. However, when presented with a load beyond fuel rack limit, the DG would begin to stall within seconds. DG frequency would decay first followed by voltage. At some point, a protective relay would actuate and isolate the Division 3 DG from the offsite source. The DG would rapidly accelerate from a reduced speed to the governor setpoint of 900 RPM due to the DG being unloaded with the DG fuel rack at its full open position. According to the vendor for the CPS Division 3 DG, the inertia and acceleration presented by this instantaneous loss of engine load would most likely carry the DG beyond its overspeed limit before the governor could respond, resulting in a DG lockout. Although the Division 3 DG is designed to withstand a full load rejection without an overspeed, it is conservative to assume the overspeed lockout occurs. No damage is expected to occur to the Division 3 DG in this scenario.

All three potential outcomes resulting from a LOOP concurrent with the Division 3 DG paralleled to an offsite source are recoverable with no damage to the DG. Moreover, these scenarios are not introduced by testing in the proposed manner. These scenarios have been previously analyzed and found to be acceptable.

The overload conditions described above would not occur if a concurrent LOCA signal is present. LOCA control logic automatically trips the DG output breaker when the DG is paralleled with an offsite source. The LOCA scenario is further discussed below.

In summary, while there is a potential for a DG lockout to occur if the DG were to experience an extreme overload condition during online testing, there is no potential to damage the Division 3 DG in any overload condition that might occur during DG testing. Moreover, as described above, none of the outcomes associated with a LOOP are introduced by testing in the proposed manner or made more likely by performing this testing on line.

Loss of Coolant Accident (LOCA)

Upon receipt of a LOCA signal while the Division 3 DG is operating in parallel with an offsite source (i.e., RAT B or the ERAT), the diesel output breaker, 252-DG1C, will trip open, leaving the 1C1 bus powered solely from the offsite source. The Division 3 DG will remain in a ready-to-load condition.

In summary, the system response to the receipt of a LOCA signal will not be changed, nor will any adverse conditions be introduced by testing in the proposed manner.

3.3 Administrative Controls for Online Maintenance

The CPS TS impose requirements and restrictions on the amount of equipment allowed out of service at any given time. Inoperable ECCS or RCIC components or DGs on the redundant division would cause entry into other more stringent Required Actions, thus providing further incentive not to perform testing on Division 3 AC Sources with redundant equipment inoperable. Additionally, the Safety Function Determination Program, required by TS Section 5.5.10, "Safety Function Determination Program (SFDP)," ensures that a loss of safety function is detected and appropriate actions taken.

The CPS approach to performing maintenance requires a protected division concept. This means that without special considerations, work is only allowed on one division at a time. Additionally, access to areas of the plant containing protected equipment is restricted. These administrative controls provide additional assurance that work is performed on only one division at a time. CPS procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities, and degraded grid conditions when paralleling a DG with offsite power. For example, during testing, only one DG at a time is operated in parallel with offsite power. This configuration provides for sufficient independence of the onsite power sources from offsite power while still enabling testing to demonstrate DG operability. In this configuration and with the administrative controls for AC Sources in place, it is only possible for one DG to be affected by an unstable offsite power system.

In summary, even if a Division 3 power source were adversely impacted while testing in the proposed manner, the impact will be limited to Division 3 AC Sources. Plant safe shutdown capability will continue to be assured by the two remaining divisions of AC Sources.

3.4 Online Risk Management

The EGC procedure WC-AA-101, "On-Line Work Control Process," provides requirements to conduct a configuration risk assessment for all maintenance performed while CPS is online. This procedure implements the requirements of paragraph (a)(4) of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." As required by this procedure, a PRA-based risk evaluation tool is used to quantify the potential risk implications of planned or emergent work activities. According to WC-AA-101, Section 4.3.3, plant risk shall be managed by the most restrictive risk threshold as defined in WC-AA-101, Attachment 3, "Configuration Risk Management Criteria."

The results of this risk evaluation are compared to specific risk thresholds. If these thresholds are exceeded, the schedule must be adjusted and appropriate risk reducing compensatory actions must be implemented prior to beginning work. These administrative controls minimize the potential to allow work on redundant or diverse SSCs such as the DGs or other systems that are similar to those supplied by the affected DG, without appropriate compensatory actions. Allowing this testing to be performed online allows this testing to be performed during a period when all Division 1 and 2 systems are required to be operable, and maximizes the time that the independent HPCS system is available for reactor pressure vessel injection during plant outages.

In accordance with WC-AA-101, Section 4.3.4, new plant risk considerations should be implemented as a change to the station's risk assessment model where appropriate. This process ensures that station's risk calculations adequately reflect the unique attributes of the plant configuration.

In summary, EGC procedures currently require an evaluation of the unique plant configurations introduced by performing SR 3.8.1.8, SR 3.8.1.11, SR 3.8.1.12, SR 3.8.1.16, and SR 3.8.1.19 online, and where appropriate, an update of the CPS risk management model to include the impact of these configurations prior to their performance while the plant is online.

3.5 Online Testing Versus Outage Testing

Due to the relationship between the Division 3 DG and the HPCS system, the TS allow up to 14 days of inoperability for the HPCS system, and consequently allow up to 14 days of inoperability for the Division 3 DG if the RCIC system is operable. Thus, the existing TS provide ample time for the online performance of the SRs that this request proposes to revise. The actual time needed to perform these SRs is approximately 16 hours. A comparison of the TS requirements for emergency core cooling systems (ECCS) (i.e., TS 3.5.1 and 3.5.2) and AC Sources (i.e., TS 3.8.1 and 3.8.2) indicates that the TS requirements are more restrictive during Modes 1, 2, or 3 than the requirements during Modes 4 or 5. Thus, due to the redundancy and

diversity of the ECCS, adequate accident mitigation equipment will be available if an event occurs while performing the subject surveillance testing during Modes 1, 2, or 3.
The HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system. As discussed in CPS USAR Sections 6.3.1.1.3 and 8.3.1.4, this system is both physically and electrically separated from the other two safety-related divisions. All controls, wiring, and other components are separated to prevent common cause failures and cross-divisional damage due to external events such as fires, pipe ruptures, falling objects, etc. The Division 3 DG supplies power to the HPCS pump motor and associated support equipment and auxiliaries. In addition, the Division 3 DG supplies power to the Division 3 Nuclear Systems Protection System (NSPS) inverter. This inverter is the normal power supply for Division 3 Reactor Protection System (RPS) instrumentation and Division 3 Source Range Monitor (SRM). The inverter loads are supported by a battery that is designed to carry the loads for up to four hours if the inverter is output voltage is lost. Due to the duration of the testing, loss of these loads is not likely. However, if the NSPS inverter were lost for greater than four hours, the associated Division 3 isolation instruments fail safe, and a loss of power to the Division 3 SRM would have no greater consequence during testing in the proposed manner than if it were lost during plant Modes currently required by TS. The Division 1 and Division 2 safety systems remain isolated from the power sources undergoing testing. Therefore, there is minimal opportunity for the performance of these SRs to have any impact on other safety-related plant equipment.

As previously discussed, the HPCS system has a full flow suction line and a return line to both the suppression pool and the RCIC storage tank, and an automatically actuated minimum flow line to the suppression pool. These features allow testing of the system online without discharging into the reactor vessel, while providing protection of the pump from overheating. Additionally, system configuration is such that HPCS system testing can be performed without impacting other divisional safety systems or the RCIC system.

During both normal plant operation and during shutdown conditions, the three 4.16 kV emergency buses are normally aligned to RAT B. The likelihood of voltage perturbations on the 4.16 kV buses during testing of the AC Sources with the plant online will not differ from the likelihood of voltage perturbation during testing of the AC Sources with CPS in a shutdown condition since loading on RAT B is not significantly different with the unit online versus during shutdown conditions, and the ERAT is sufficiently rated to preclude any testing-induced voltage perturbations.

Safety buses 1A1, 1B1, and 1C1 are normally aligned to RAT B during normal at power operation. RAT B is sized to handle all startup, shutdown, trip, and LOCA loading. Normal safety bus loading on RAT B at power is between 2.19 MW and 2.21 MW. Shutdown loading on RAT B ranges from 1.8 MW to 3.2 MW. As previously discussed, the rating of RAT B is 33.3 MVA. MODE 1 summer operation with Class 1E and non-1E loads fed from RAT B presents a load of 16.13 MVA. Adding 2.02 MW at 0.80 power factor (i.e., 2.53 MVA) for Division 3 AC Sources would result in a load of 18.66 MVA. This is only 56% of RAT B rated capability. In addition, non-1E loads will be powered from UAT 1A, not RAT B, during this testing.

The ERAT is normally in a standby alignment during normal plant operation and is sufficiently rated to carry the loads of all three safety buses and to provide all 1E LOCA loads. Normal online safety bus loading for all three safety buses is approximately 2.2 MW. Addition of the Division 3 Class 1E loads will result in an ERAT load of approximately 4.23 MW versus the ERAT rating of 30 MVA. This is well within the rating of the ERAT.

The HPCS loads are less than 10% of RAT B and ERAT ratings. Moreover, there is no configuration presented by this testing that would compromise the integrity of either transformer. There are no additional concerns introduced by performing these tests online versus performing offline based on electrical loading. In summary, there is no configuration introduced by testing in the proposed manner that would approach the rating of RAT B or the ERAT.

CPS has SVCs installed on the output of the ERAT and RAT B. The purpose of the SVCs is to maintain safety bus voltage, and compensate for any transmission system voltage fluctuations that might occur. This voltage compensation will be available during testing with the Division 3 DG operating in parallel with offsite power in all modes of plant operation. The time delay features of the degraded voltage sensors are designed to allow small, brief perturbations to settle out well before actual trips would occur, ensuring that no transients will be introduced by the actuation of protective relays at power.

The proposed license amendment does not alter any of the TS-required DG surveillance test frequencies; thus, the total number of tests and associated transients would be unchanged by performing this testing online versus during shutdowns.

According to the CPS USAR, the maximum total Division 3 DG load for a simultaneous LOCA and LOOP is 2020 kW, with the largest load being the 1838 kW HPCS pump (i.e., approximately 91% of the total Division 3 DG load). As previously discussed, the Division 3 load is a small percentage of the ERAT and RAT B ratings and would be considered a normal load for the offsite power system. Energizing or de-energizing a load of this size as part of DG surveillance testing online or during shutdown conditions, creates minimal potential to cause a significant electrical distribution system perturbation. In fact, HPCS pump starts are routinely performed online to satisfy quarterly inservice testing requirements, without disturbing plant operations. In summary, starting the HPCS pump online is a routine evolution; therefore, there is no potential to create an electrical distribution system perturbation introduced by testing the HPCS system in the proposed manner.

The on-line performance of the subject SRs for the Division 3 DG will have little effect on managing equipment unavailability goals described in 10 CFR 50.65(a)(3). The maintenance rule unavailability performance criterion for the Division 3 DG is set at 366 hours for a 24-month rolling period. Based on this criterion, CPS has established an administrative goal of 125 hours of unavailability for the 24- month period. In summary, the addition of 16 hours of unavailability per 24-month period does not challenge achievement of the EGC-established performance criteria for the Division 3 DG.

3.6 Discussions for Individual Surveillance Requirements

3.6.1 SR 3.8.1.8

For Division 3, SR 3.8.1.8 requires verification of the transfer of unit power supply from the normal to the alternate offsite circuit in both automatic and manual modes.

For Division 3, the verification of the automatic transfer from the normal to the alternate offsite circuit (i.e., RAT B to ERAT) is limited to Bus 1C1, and is accomplished by simulating a loss of RAT B by opening test switches on the Bus 1C1 main feed breaker and verifying that the main feed breaker opens and that the Bus 1C1 reserve feed breaker closes. In addition, an automatic transfer from the normal offsite source to the alternate offsite source for Division 3 is accomplished by: tripping the Bus 1C1 main feed breaker by placing its control switch in the pull to lock position, verifying that the Bus 1C1 main feed breaker opens, and verifying that the Bus 1C1 reserve feed breaker closes and energizes the 1C1 4.16 kV Bus.

The performance of SR 3.8.1.8 for Division 3 does not require verification that Bus 1C1 will automatically transfer back to RAT B; however, this test is performed to ensure that RAT B remains operable. This verification is accomplished by: tripping the Bus 1C1 main feed breaker through placement of its control switch in the pull to lock position, verifying that the Bus 1C1 reserve feed breaker opens, and verifying that the Bus 1C1 main feed breaker closes and energizes Bus 1C1.

Currently, this SR contains a Note that prohibits performance in Modes 1 or 2. The TS Bases state that the reason for this 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.

First, as previously discussed, the Division 3 electrical loads do not approach the electrical load rating of either RAT B or the ERAT; therefore, there is no impact to the electrical distribution system, and no mechanism for challenging continued steady state operation when performing this SR for Division 3. In addition, buses are manually transferred on a routine basis to support monthly testing of the DG.

Lastly, the HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system (i.e., Division 3). When performing this SR for Division 3, the simulated loss of RAT B signal and the breaker manipulations discussed above are generated only in the Division 3 logic and do not affect the other two safety-related electrical divisions. Furthermore, Division 3 loads such as the Division 3 SRM and RPS isolation features are supported by a battery that is designed to carry these loads for up to four hours. Thus, performing SR 3.8.1.8 for Division 3, whether shutdown or online, affects only the HPCS system.

Therefore, the reasons for the mode restrictions stated in the TS Bases for SR 3.8.1.8 are not valid for the Division 3 AC Sources.

3.6.2 SR 3.8.1.11

For Division 3, SR 3.8.1.11 requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated LOOP signal, achieves the required voltage and frequency, and supplies permanently connected loads for ≥ 5 minutes. Note that the CPS design for the Division 3 DG does not feature automatic sequencing of loads.

With the Division 3, 4.16 kV emergency bus aligned to RAT B, a LOOP is simulated by the use of relay test switches that cause the Division 3 emergency switchgear to de-energize, thereby isolating the Division 3 electrical subsystem from the other two safety-related electrical subsystems. The Division 3 DG starts, re-energizes its associated emergency bus, and runs for at least 5 minutes. Since this test does not involve an ECCS initiation signal, the HPCS pump does not automatically start. Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state the reason for this Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems.

First, although the offsite source of power to the Division 3 emergency bus is disconnected when performing this SR for Division 3, the period of time that this condition exists is small and is acceptable since the HPCS system is already inoperable for performance of the test. As discussed in the Note to the Applicability requirements for TS 3.8.1, the Division 3 AC electrical power system is not required to be operable when the HPCS system is inoperable.

Secondly, due to the relative size of the loads associated with the HPCS system and the Division 1 and Division 2 safety systems remain isolated from the power sources undergoing testing, there is minimal potential when performing this testing for Division 3 to create an offsite power supply perturbation that could affect the Division 1 and 2 safety systems when the Division 3, 4.16 kV emergency bus is de-energized.

Lastly, the Division 3 power system is an independent electrical distribution system with a dedicated DG. Division 3 loads such as the Division 3 SRM and RPS isolation features are supported by a battery that is designed to carry these loads for four hours; therefore, there is minimal opportunity for the performance of this SR for the Division 3 DG to have any impact on other safety-related plant equipment or normal plant operation. The simulated LOOP signal is generated only at the Division 3 switchgear and does not affect the other two safety-related electrical divisions or their associated loads.

Therefore, the reasons for the Mode restrictions stated in the TS Bases for SR 3.8.1.11 are not valid for the Division 3 DG.

3.6.3 SR 3.8.1.12

For Division 3, SR 3.8.1.12 requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated ECCS initiation signal, achieves the required voltage and frequency within the specified time, and operates for ≥ 5 minutes.

For Division 3, this test is performed by inserting an ECCS initiation signal into the Division 3 control logic (e.g., by arming and depressing the HPCS manual initiation pushbutton on the main control room panel). With the ECCS initiation signal present, the Division 3 DG starts and runs unloaded (i.e., generator output breaker is open) for ≥ 5 minutes while acceptable performance parameters (voltage and frequency) are verified. The HPCS pump start is manually overridden by removing the close and trip fuses for the pump motor breaker, and opening of the motor-operated injection valve (i.e., 1E22-F004) is prevented by verifying the valve is closed and de-energized (by placing the breaker for the valve motor in the OFF position). These steps are taken to prevent an actual discharge of water into the reactor vessel by the HPCS system, which could cause unwanted effects on reactor vessel water level. Similar steps would likewise be taken when performing this test online to preclude unwanted effects on reactor vessel water level and core reactivity due to a HPCS system injection. Following the test, restoration of all safety-related functions, including restoration of the HPCS system to operable status, are independently verified. Similar methods and procedural controls would be employed when performing the surveillance test online.

Currently, this SR contains a Note that prohibits performance in Modes 1 or 2. The TS Bases state the reason for this Note is that performing the surveillance could cause perturbations to the electrical distribution system that could challenge continued steady state operation and, as a result, plant safety systems. First, since this test is conducted with the Division 3 DG unloaded and isolated from its emergency bus when performing this SR for Division 3, there is no impact to the electrical distribution system, and no mechanism for challenging continued steady state operation.

Lastly, the Division 3 power system is an independent electrical distribution system with a dedicated DG. Division 3 loads such as the Division 3 SRM and RPS isolation features are supported by a battery that is designed to carry these loads for four hours; therefore, there is minimal opportunity for the performance of this SR for the Division 3 DG to have any impact on other safety-related plant equipment or normal plant operation. When performing this SR for Division 3, the simulated ECCS initiation signal is generated only in the HPCS logic and does not affect the other two safety-related electrical divisions or their associated loads. Thus, performing the SR 3.8.1.12 test for the Division 3 DG, whether shutdown or online, affects only the HPCS system.

Therefore, the reasons for the mode restrictions stated in the TS Bases for SR 3.8.1.12 are not valid for the Division 3 DG.

3.6.4 SR 3.8.1.16

For Division 3, SR 3.8.1.16 requires verification that the Division 3 DG can be synchronized with the offsite power source while loaded with emergency loads, and upon a simulated restoration of offsite power, all loads are transferred to offsite power and the DG returns to ready-to-load operation.

The Division 3 test is typically performed following completion of the LOOP test of SR 3.8.1.11 for aligning the Division 3, 4.16 kV emergency bus to RAT B, and following completion of the LOOP/LOCA test of SR 3.8.1.19 for aligning the Division 3, 4.16 kV emergency bus to RAT B. After the Division 3 DG has started and re-energized its associated emergency bus, the HPCS pump is started and placed in the full flow test mode. Actual discharge of water into the reactor vessel by the HPCS system is prevented as discussed under SR 3.8.1.19. The Division 3 emergency bus is then paralleled to offsite power and the bus loads are transferred to the offsite power source. The DG output breaker is then opened and the DG is verified to return to ready-to load operation.

Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state the reason for this Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems.

First, although the offsite source of power to the Division 3 emergency bus is disconnected at the beginning of this test when performing this SR for Division 3, the period of time that this condition exists is small and is acceptable since the HPCS system is already declared inoperable for performance of the test; therefore, the Division 3 DG is not required to be operable as discussed in the Note associated with the Applicability requirements for TS 3.8.1.

Secondly, the offsite power source for the Division 3, 4.16 kV emergency bus during the test is the ERAT or RAT B, regardless of whether the test is performed online or during shutdown conditions. Completed test results performed during shutdown conditions have shown that the required bus voltage parameters remain within expected limits and no anomalous actions regarding load transfer sequences occur. Conducting this test for Division 3 online is not expected to be more challenging to plant safety systems than performance during shutdown conditions. Additionally, as discussed in Section 3.5, due to the relative size of the loads associated with the HPCS system (i.e., 2020 kW), there is minimal potential for creating an offsite power supply perturbation when shifting the load between the Division 3 DG and the offsite power source.

Lastly, the HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system. The HPCS system has a full flow suction line and a return line to both the suppression pool and the RCIC storage tank, and an automatically actuated minimum flow line to the suppression pool. These features allow testing of the system online without discharging into the reactor vessel, while providing protection of the pump from overheating. Additionally, system configuration is such that HPCS system testing can be performed without impacting other divisional safety systems or the RCIC system. Energizing or de-energizing loads of this size as part of surveillance testing online or during shutdown conditions creates minimal potential to cause an electrical distribution system perturbation. In fact, HPCS pump starts are routinely performed online to satisfy quarterly inservice testing requirements, without disturbing plant operations. In addition, Division 3 loads such as the Division 3 SRM and RPS isolation features are supported by a battery that is designed to carry these loads for four hours. Consequently, there is minimal opportunity for the performance of this SR for Division 3 DG to have any impact on other safety-related plant equipment or normal plant operation.

Therefore, based on the above discussion, the reasons for the mode restrictions stated in the TS Bases for SR 3.8.1.16 are not valid for the Division 3 DG.

3.6.5 SR 3.8.1.19

For Division 3, SR 3.8.1.19 requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated LOOP signal in conjunction with an actual or simulated ECCS initiation signal, achieves the required voltage and frequency within the specified time, and supplies permanently connected loads for ≥ 5 minutes.

For Division 3, this test is currently performed with the Division 3, 4.16 kV emergency bus aligned to RAT B. A LOOP signal is simulated, causing the Division 3 switchgear to de-energize (e.g., by opening test switches simulating bus undervoltage). Following the DG start signal, an ECCS initiation signal is inserted into the Division 3 control logic (e.g., by arming and depressing the HPCS manual initiation pushbutton on the main control room panel). The Division 3 DG starts, re-energizes its associated emergency bus, and powers the HPCS pump and other permanently connected loads. For this test, the HPCS pump suction is from the RCIC tank, and pump discharge is through the test return line back to the RCIC tank. The HPCS system discharge pathway to the reactor vessel is isolated.

Actual discharge of water into the reactor vessel by the HPCS system is prevented during the current performance of this test during shutdown conditions in order to preclude unwanted effects on reactor vessel water level. Discharge into the reactor vessel would likewise be prevented when performing this test online to preclude unwanted effects on reactor vessel water level and core reactivity. The current method of preventing HPCS system discharge into the reactor vessel is by shutting HPCS manual isolation valve 1E22-F036. However, since 1E22-F036 is in the CPS Drywell and inaccessible during operation at power, the prevention of HPCS system discharge into the reactor vessel could be accomplished by other means such as verifying that motor-operated injection valve 1E22-F004 is closed and de-energized by placing the breaker for the valve motor in the OFF position. Following the test, restoration of all safety-related functions, including restoration of the HPCS system to operable status, are independently verified.

Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state 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 plant safety systems.

First, although the offsite source of power to the Division 3 emergency bus is disconnected when performing this SR for Division 3, the period of time that this condition exists is small and is acceptable since the HPCS system is already inoperable for performance of the test;

therefore, the Division 3 DG is not required to be operable as discussed in the Note associated with the Applicability requirements for TS 3.8.1.

Secondly, as discussed in Section 3.5, there is no configuration introduced by testing in the proposed manner that would approach the rating of RAT B or the ERAT when performing this SR for Division 3. Due to the relative size of the loads associated with the HPCS system (i.e., 2020 kW), there is minimal potential for this testing to create an offsite power supply perturbation when the Division 3 electrical bus is de-energized. Furthermore, HPCS pump starts are routinely performed online to satisfy quarterly inservice testing requirements, without disturbing plant operation.

Lastly, as previously discussed, the HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system. The HPCS system has a full flow suction line and a return line to both the suppression pool and the RCIC storage tank, and an automatically actuated minimum flow line to the suppression pool. These features allow testing of the system online without discharging into the reactor vessel, while providing protection of the pump from overheating. Additionally, system configuration is such that HPCS system testing can be performed without impacting other divisional safety systems or the RCIC system. Energizing or de-energizing loads of this size as part of surveillance testing online or during shutdown conditions creates minimal potential to cause an electrical distribution system perturbation. In fact, HPCS pump starts are routinely performed online to satisfy quarterly inservice testing requirements, without disturbing plant operations. In addition, Division 3 loads such as the Division 3 SRM and RPS isolation features are supported by a battery that is designed to carry these loads for four hours; therefore, there is minimal impact resulting from the performance of this SR for Division 3 on other safety-related plant equipment. The simulated LOOP and ECCS initiation signals associated with this SR for Division 3 affect only the HPCS system and do not affect the other two safety-related electrical divisions.

Based on the above discussion and plant experience related to performing this test, conducting this test online for the Division 3 DG is no more challenging than conducting the test while shutdown; therefore, the reasons for the mode restrictions stated in the TS Bases for SR 3.8.1.19 are not valid for the Division 3 DG.

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

10 CFR 50, Appendix A, General Design Criteria (GDC) 17, "Electrical Power Systems," requires, in part, that:

- An onsite and offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety;
- The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure;
- Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of

way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions; and

- Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

10 CFR 50, Appendix A, GDC 18, "Inspection and Testing of Electrical Power Systems," requires, in part, that electrical power systems important to safety be designed to permit appropriate inspection and testing of important areas and features.

The proposed TS changes affect only the plant operating conditions during which certain Division 3 (i.e., HPCS) AC Sources surveillance tests can be performed. The technical evaluation of the proposed changes demonstrates that performing these surveillance tests while online will not create a transient that could cause perturbations to the CPS electrical distribution system, disrupt power operation, or challenge plant safety systems. For these same reasons, the proposed changes do not alter CPS's compliance with the requirements of GDC 17 and GDC 18.

4.2 Precedents

The NRC has approved similar license amendments to remove operating mode restrictions for performing Division 3 DG surveillance testing. Recent examples include:

- Nine Mile Point Nuclear Station, Unit No. 2 (License Amendment No. 133 issued by NRC letter dated March 18, 2010 – ADAMS Accession No. ML100460016)

- Columbia Generating Station (License Amendment No. 203 issued by NRC letter dated March 23, 2007 - ADAMS Accession No. ML070640060; and License Amendment No. 173 issued by NRC letter dated May 18, 2001 - ADAMS Accession No. ML011440088).

- Grand Gulf Nuclear Station (License Amendment No. 155 issued by NRC letter dated September 10, 2002 - ADAMS Accession No. ML030760726).

Similar to CPS, all of the above plants have a stand-alone HPCS system with a dedicated DG and independent electrical distribution system, and with a motor-driven HPCS pump as the largest load.

4.3 No Significant Hazards Consideration

Exelon Generation Company, LLC (EGC) is requesting an amendment to Facility Operating License NPF-62 for Clinton Power Station, Unit 1 (CPS). The proposed amendment would modify Technical Specifications (TS) Section 3.8.1, "AC Sources - Operating," by revising certain Surveillance Requirements (SRs) pertaining to the Division 3 AC Sources. The Division 3 power system is an independent source of onsite alternating current (AC) power primarily dedicated to the High Pressure Core Spray (HPCS) system. The TS currently prohibit performing the testing required by certain SRs in either Modes 1 or 2, or in Modes 1, 2, or 3. The proposed amendment would also remove these Mode restrictions and allow certain SRs to be performed in any operating Mode for the Division 3 AC Sources.

EGC has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment," as discussed below:

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

   Response: No

   The Division 3 (i.e., HPCS) diesel generator (DG) and its associated emergency loads are accident mitigating features, not accident initiators. Therefore, the proposed TS changes to allow the performance of certain Division 3 AC Sources surveillance testing in any plant operating Mode will not significantly impact the probability of any previously evaluated accident.

   The design of plant equipment is not being modified by the proposed changes. As such, the ability of the Division 3 AC Sources to respond to a design basis accident will not be adversely impacted by the proposed changes. Testing procedures include steps to ensure that injection into the reactor vessel is precluded. The proposed changes to the TS surveillance testing requirements for the Division 3 AC Sources do not affect the operability requirements for the AC Sources, as verification of such operability will continue to be performed as required. Continued verification of operability supports the capability of the Division 3 AC Sources to perform their required functions of providing emergency power to HPCS system equipment, consistent with the plant safety analyses. Limiting testing to only one AC Source at a time ensures that design basis requirements are met. Should a fault occur while testing the Division 3 AC Sources, there would be no significant impact on any accident consequences since the other two divisional AC Sources and associated emergency loads would be available to provide the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

   Therefore, the proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No

   No changes are being made to the plant that would introduce any new accident causal mechanisms. Equipment will be operated in the same configuration with the exception of the plant operating mode in which the Division 3 AC Sources surveillance testing is conducted. Performance of these surveillances tests while online will continue to verify operability of the Division 3 AC Sources. The proposed amendment does not impact any plant systems that are accident initiators and does not adversely impact any accident mitigating systems.

Therefore, the proposed amendment does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

   Response: No.

   Margin of safety is related to confidence in the ability of the fission product barriers (fuel cladding, reactor coolant system, and primary containment) to perform their design functions during and following postulated accidents. The proposed changes to the TS surveillance testing requirements for the Division 3 AC Sources do not affect the operability requirements for the AC Sources, as verification of such operability will continue to be performed as required. Continued verification of operability supports the capability of the Division 3 AC Sources to perform their required function of providing emergency power to HPCS system equipment, consistent with the plant safety analyses. Consequently, the performance of the fission product barriers will not be adversely impacted by implementation of the proposed amendment. In addition, the proposed changes do not alter setpoints or limits established or assumed by the accident analysis. Further, performing Division 3 AC Sources surveillance activities online increases the Division 3 DG and HPCS system availability during refueling outages and allows the testing of the Division 3 systems to be conducted when both Division 1 and 2 systems are required to be OPERABLE.

   Therefore, the proposed amendment does not involve a significant reduction in a margin of safety.

Based on the above, EGC concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of no significant hazards consideration is justified.

4.4 Conclusions

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or a significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

1. Letter from R. V. Guzman (NRC) to S. L. Belcher (Nine Mile Point), Nine Mile Point Nuclear Station, Unit No. 2 – Issuance of Amendment Regarding Removal of Operating Mode Restrictions for Performing High Pressure Core Spray Emergency Diesel Generator Surveillance Testing (TAC No. ME1042), dated March 18, 2010

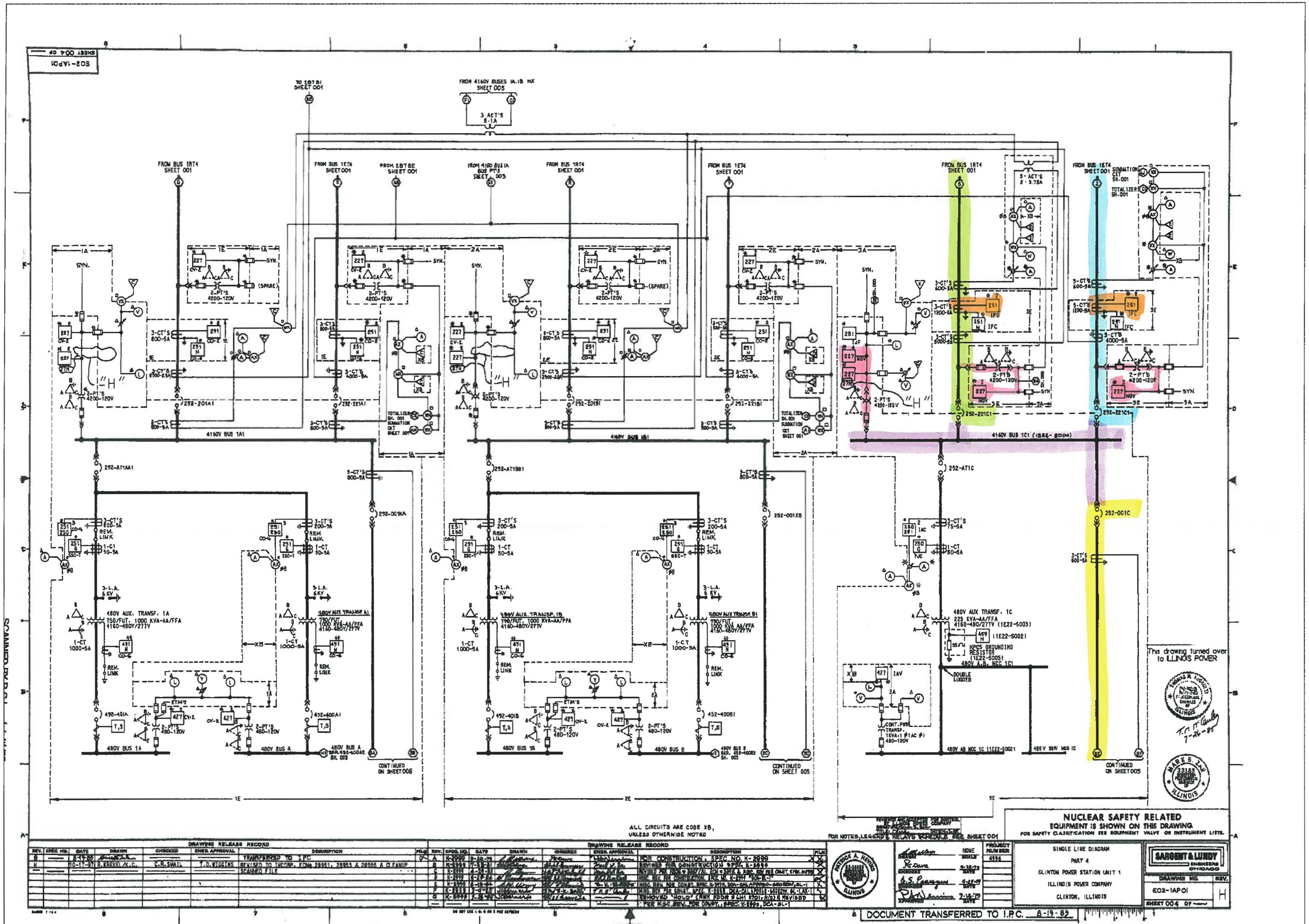
2. Letter from C. F. Lyon (NRC) to J. V. Parrish (Energy Northwest), Columbia Generating Station – Issuance of Amendment Re: Removal of Operating Mode Restrictions for Performing Emergency Diesel Generator Surveillance Testing (TAC No. MD2113), dated March 23, 2007

3. Letter from D. Jaffe (NRC) to W. A. Eaton (Entergy Operations, Inc.), Grand Gulf Nuclear Station, Issuance of Amendment Re: Removal of Operating Mode Restrictions for Performing High Pressure Core Spray Emergency Diesel Generator Testing (TAC No. MB4261), dated September 10, 2002

Attachment 2
Clinton Power Station Electrical Drawings

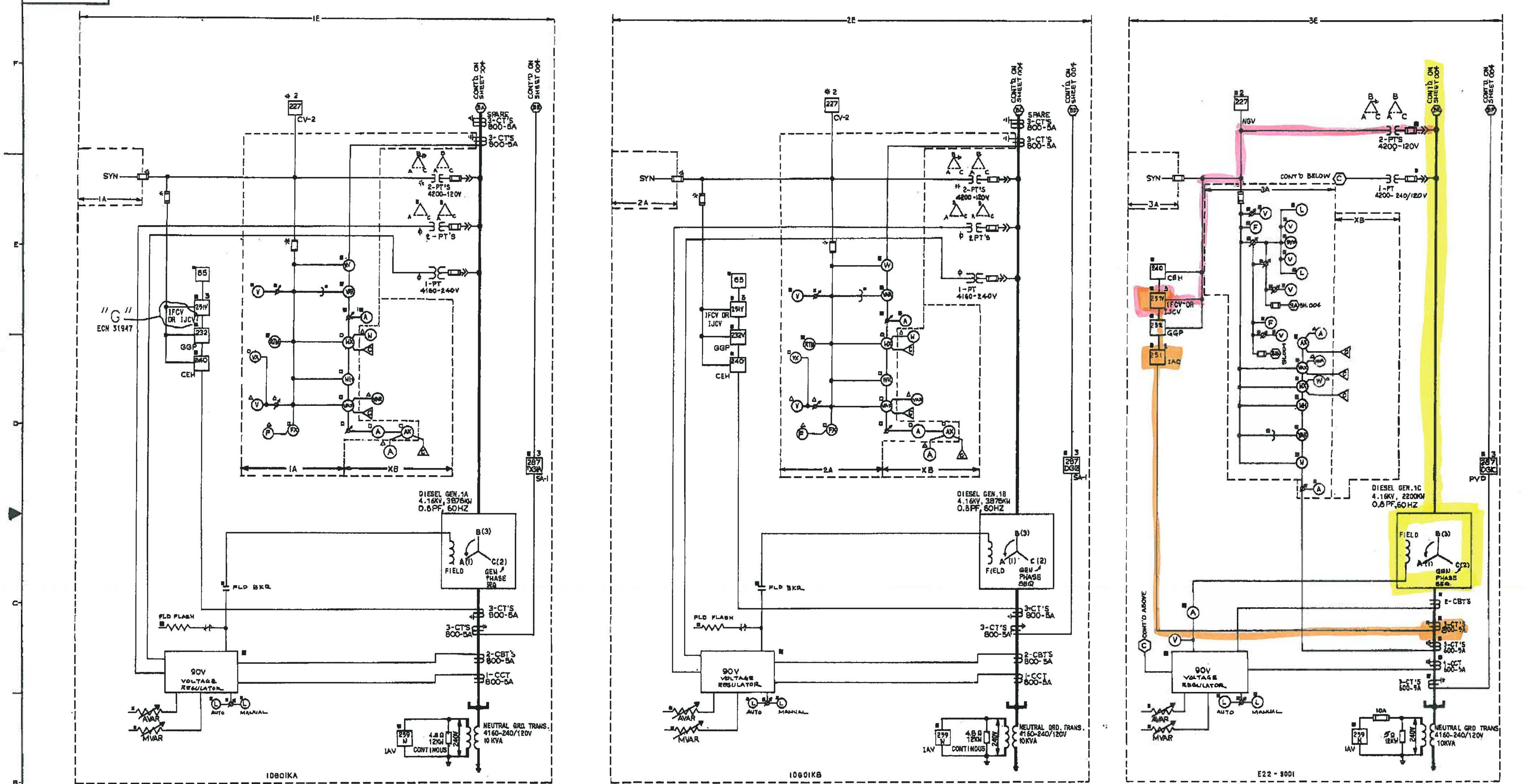
<u>Clinton Power Station Electrical Single Line Diagrams and Relay Settings Tables</u>

E02-1AP01, Sheet 4, Single Line Diagram Part 4
E02-1AP01, Sheet 5, Single Line Diagram Part 5
E02-1AP01, Sheet 1, Single Line Diagram Part 1
E02-1AP04, Sheet 1, 4160V and 6900V SWGR Relay Settings
E02-1AP04, Sheet 17, Diesel Generator 1A, 1B, and 1C Relay Settings


E02-1AP01
SHEET 004 OF
4160V BUS 1A1
4160V BUS 1B1
4160V BUS 1C1 (1E22-S004)
480V AUX. TRANSF. 1A
480V AUX TRANSF. 1C
480V BUS 1A
480V BUS 1B
480V AB MCC 1C (1E22-S0021
480V SSW MCC 1C
CONTINUED ON SHEET 005
This drawing turned over to ILLINOIS POWER
ALL CIRCUITS ARE CODE XB, UNLESS OTHERWISE NOTED
FOR NOTES, LEGEND & RELAYS SCHEDULE SEE SHEET 001
NUCLEAR SAFETY RELATED
EQUIPMENT IS SHOWN ON THIS DRAWING
FOR SAFETY CLASSIFICATION SEE EQUIPMENT VALVE OR INSTRUMENT LISTS.
DRAWING RELEASE RECORD
SINGLE LINE DIAGRAM
PART 4
CLINTON POWER STATION UNIT 1
ILLINOIS POWER COMPANY
CLINTON, ILLINOIS
SARGENT & LUNDY ENGINEERS CHICAGO
PROJECT NUMBER 4536
DRAWING NO. E02-1AP01
REV. H
DOCUMENT TRANSFERRED TO I.P.C. 8-19-85

xy=0,0

E02-1AP01



FOR NOTES, LEGEND & RELAYS SCHEDULE SEE SHEET 1

CHECK THE DESIGN STATUS SYSTEM FOR STAMP AFFIXED CHANGE DOCUMENTS WHICH MAY AFFECT THIS DRAWING.

REVIEWED AND ACCEPTED FOR CONTROL BY ILLINOIS POWER COMPANY

NUCLEAR SAFETY RELATED
EQUIPMENT IS SHOWN ON THIS DRAWING.
(FOR SAFETY CLASSIFICATION SEE EQUIPMENT, VALVE OR INSTRUMENT LISTS.)

DRAWING RELEASE RECORD

REV.	SPEC. NO.	DATE	DRAWN	CHECKED	ENGR. APPROVAL	DESCRIPTION
A	K-2999	3-14-79				FOR CONSTRUCTION, SPEC. NO. K-2999
B	K-2999	7-22-81				REVISED FOR CONSTRUCTION SPEC No. K-2999
C	K-2999	1-18-85				MISC. REV. FOR CONST., SPEC. K-2999, DCA-SL-1.
D	K-2999	3-6-85				MISC. REV. FOR CONST. SPEC. K-2999, DCA-CALAPOOLE-6900W, SL-1
D	—	04-08-85		—	—	TRANSFERRED TO IPC
E	K-2999	04-28-86			—	REV. PER ECN #1480, FOR CONST. SPEC. K-2999, DCA-SL-1
F		4-20-00	R KREKEL	J.A. ZUMBAHLEN	J.A. ZUMBAHLEN	REVISED TO INCORPORATE ECN 31948, ECN 31949 & D43 PROCEDURE.
G		05/04/00	J.A. ZUMBAHLEN	K. NELSON	K. NELSON	REVISED TO INCORPORATE ECN 31947.

DO NOT USE I, O, Q OR X FOR REVISION

E. Schumacher 1/18/15

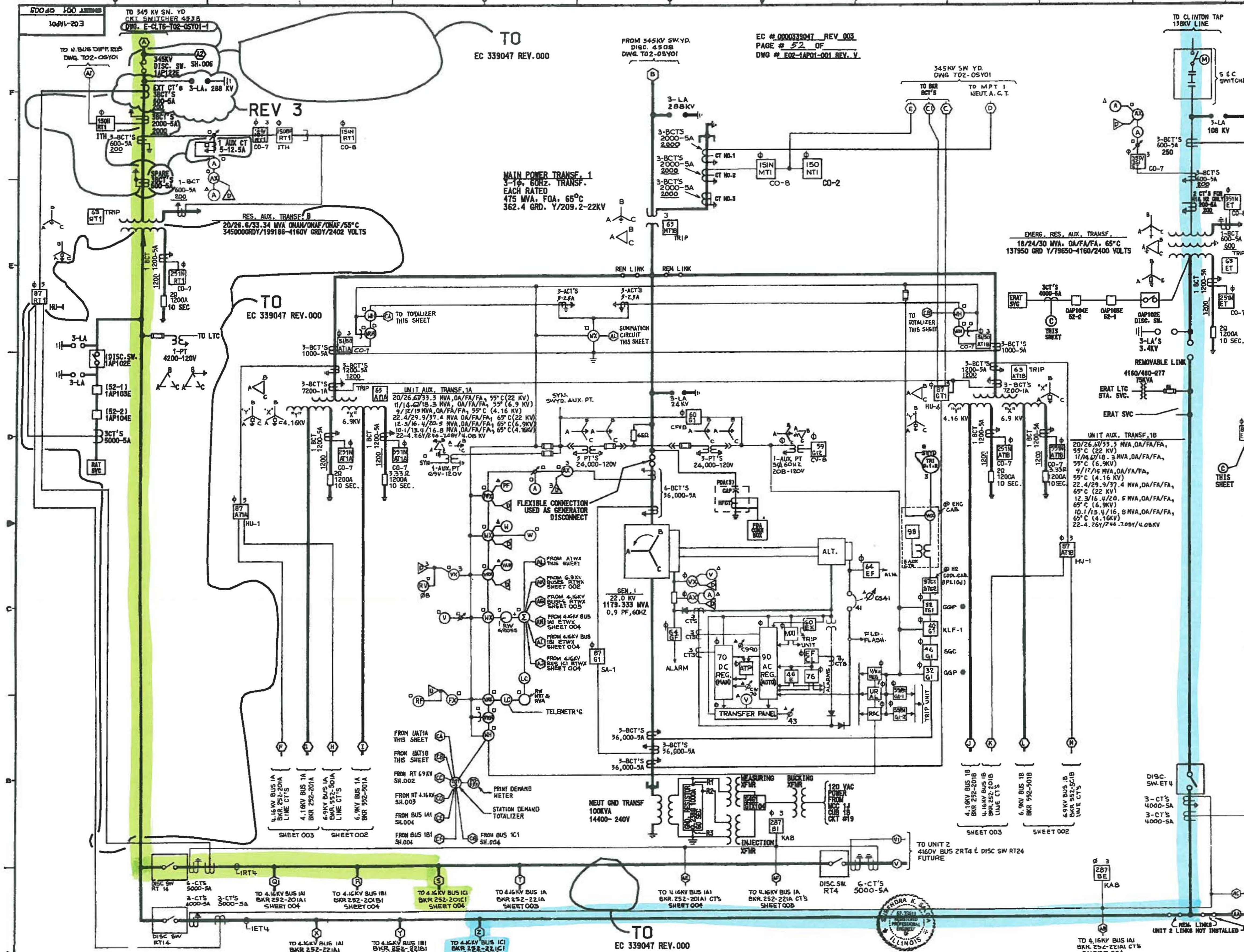
DRAWN — SCALE None
CHECKED — DATE 9-28-79
ENGINEER — DATE 9-28-79
APPROVED — DATE 9-28-79

PROJECT NUMBER 4536

SINGLE LINE DIAGRAM
PART 5
CLINTON POWER STATION UNIT 1
CLINTON, ILLINOIS

SARGENT & LUNDY ENGINEERS CHICAGO

DRAWING NO.	REV.
E02-1AP01	G
SHEET 005 OF FINAL	



RELAY SCHEDULE & DEVICE NO'S

DEV. NO	G.E.	WHSG HSE	ABB	FUNCTION
27	NGV	CV-2	27N	UNDERVOLTAGE RELAY
32	GGP	CRN-1		DIRECTIONAL POWER RELAY
37				NO STATOR COOLING TURBINE RUNBACK
40		KLF-1		LOSS OF FIELD RELAY
41E				VOLTAGE REGULATOR SUPPLY BREAKER
46	SGC SEE NOTE 5			NEGATIVE PHASE SEQUENCE RELAY
46E				EXCITER FLD OVER CURR.
50G		ITH		GROUND FAULT DETECTOR
50BF		ITH		BREAKER FAILURE RELAY
50H		ITH		
51G	IAC			GROUND OVERCURRENT RELAY
51/50		CO-2,4, 29		PHASE OVERCURRENT RELAY
50N/51N		CO-2,6, 7,8,ITH		NEUTRAL OVERCURRENT RELAY
51V	IJCV	COV		VOLTAGE CONTROLLED OR RESTRAINED OVERCURRENT RELAY
59	PJC	CV-8		GEN. OVERVOLTAGE GROUND RELAY
59E				FIELD FORCING RELAY
60	CFVB			VOLTAGE BALANCE RELAY
63	900-1	SPR		SUDDEN PRESSURE RELAY
64GF				GENERATOR FIELD GROUND RELAY
64EF		PSG		EXCITER FIELD GROUND RELAY
70				DC (MANUAL) REGULATOR
70M				DC REGULATOR SET POINT ADJUSTER
76				EXCITER FLD OVER CURR. RELAY
81	IJF			OVER-FREQUENCY RELAY
87AT		HU-1		AUX. TRANS. DIFFERENTIAL RELAY
87ET		HU-1		EMERG. RES. AUX. TRANS. DIFFERENTIAL RLY
87G		SA-1		GENERATOR DIFFERENTIAL RELAY
87GT		HU-4		GEN. TRANS. DIFFERENTIAL RELAY
87RT		HU-4		RES. AUX. TRANS. DIFFERENTIAL RELAY
87B		KAB		BUS DIFFERENTIAL RELAY
87NT		ITH		GEN LINE GROUND FAULT
87DG	CFD	SA-1		DIESEL GEN. DIFFERENTIAL RELAY
90				AC (AUTOMATIC) REGULATOR
90M				AC REGULATOR SET POINT ADJUSTER
59/81	STV			VOLTS/HERTZ RELAY
98				POWER LOAD UNBALANCE

LEGEND

- I,T S,G: INSTANTANEOUS (I), LONG TIME DELAY (T), SHORT TIME DELAY (S), GRD TIME DELAY (G) — AIR CIRCUIT BREAKER DRAW-OUT TYPE ELECTRICALLY TRIPPED BY STATIC TRIP DEVICE
- F FREQUENCY METER
- PHASE SHIFTING TRANSF.
- FX FREQ. TRANSDUCER
- A AMMETER
- V VOLTMETER
- AX AMPERE TRANSDUCER
- VAR VARMETER
- TR TRANSIENT RECORDERS & CHANNEL ASSIGNMENT
- VARX VAR TRANSDUCER
- L POTENTIAL IND. LIGHT
- VARH VAR HOUR METER
- LC LOAD CONTROL
- VX VOLT TRANSDUCER
- PF POWER FACTOR METER
- W WATTMETER
- PFX POWER FACTOR TRANSDUCER
- WH WATTHOUR METER
- RF RECORDING FREQ. METER
- WX WATT TRANSDUCER
- RV RECORDING VOLTMETER
- Σ SUMMATION
- RW RECORDING WATTMETER
- INSTRUMENT SWITCH
- PMS CPTR. INPUT
- RVAR RECORDING VARMETER
- OCS CPTR. INPUT
- ST SHUNT TRIP
- EFCL EXCITER FIELD CURRENT LIMITER
- ATP AUTO TRACKING PANEL
- MXL MAXIMUM EXCITATION LIMITER
- RDC REACTIVE DROOP COMPENSATOR
- URAL UNDER EXCITED REACTIVE AMPERES AMPERES LIMITER

NOTES

1. PREFIX CODES:
   INDICATE VOLTAGE (NO PREFIX REFERS TO GEN. VOLTAGE OR DEVICES THAT SERVE SEVERAL VOLTAGES)
   1. REFERS TO 345KV
   2. REFERS TO 4160V
   3. REFERS TO 138KV
   4. REFERS TO 480Y
   5. REFERS TO 6900V
2. LOCATION CODES
   (X) MATCH LETTER / MATCH HEXAGON
   A MCR - CONSOLE 1H13-P680
   Δ MCR - BENCHBOARD - 1H13-P870, 877, & 601
   D MCR - BACKROW VERT. PNL. - 1H13-P827, 822, 640, 852, & 862
   ■ LOCAL VERTICAL PANEL 1H22 PNLS & LP PNLS
   ✱ LOCAL SWITCHGEAR OR MCC
   Φ GEN. & TRANSFORMER RLY. PANELS (EL. 781'-0")
3. CLASSIFICATION/SEGREGATION CODES:
   XB - NON-CLASS 1E, NON-ASSOCIATED
   1E - CLASS 1E, DIVISION 1
   2E - CLASS 1E, DIVISION 2
   3E - CLASS 1E, DIVISION 3
   1A - NON-CLASS DIVISION 1 ASSOCIATED
   2A - NON-CLASS DIVISION 2 ASSOCIATED
   3A - NON-CLASS DIVISION 3 ASSOCIATED
4. ALL CIRCUITS ARE CODE XB UNLESS OTHERWISE NOTED.
5. EXCITER PHASE FAULT DETECTOR IS G.E. # 387982MA305. FOR DETAILS SEE DWG. E02-1MP99 SH. 022.

MARK S. ZAR 33185 REGISTERED PROFESSIONAL ENGINEER OF ILLINOIS
2/15/84

DRAWING RELEASE RECORD

REV.	SPEC. NO.	DATE	DRAWN	CHECKED	ENGR. APPROVAL	DESCRIPTION	FILM
H		6-7-94	TSS/T SOBOTTKA	D HANK	J EMMERT	REVISED TO INCORPORATE ECN 27403	
J		8-10-94	TSS/T SOBOTTKA	D HANK	J EMMERT	REVISED PER D.46 TO INCORPORATE DRAFTING ID 07204	
K		10-27-95	K.LOWE/	C. B. SMAIL	T. O. WIGGINS	REVISED TO INCORPORATE D-46 #07543 AND CLEAN-UP SCANNED FILE	
L		10-25-97	KEC/RAK/KC	C. B. SMAIL	T. O. WIGGINS	REVISED TO INCORPORATE ECNs 23863, 30102, AND 30168	
M		05/21/99	J. ZUMBAHLEN	R. KREKEL	R. KREKEL	REVISED TO INCORPORATE ECNs 30526, 30532, 30545, 31226, 31616 & D.43 PROCEDURE.	
N		09/21/99	K. NELSON	K.E. CROUCH	K.E. CROUCH	REVISED TO INCORPORATE D.46 07942 AND D.43 PROCEDURE	
P		1-25-02	R KREKEL	J LYNCH	D.G.T.	REVISED TO INCORPORATE EC 334510 REV 1	

DRAWING RELEASE RECORD

REV.	SPEC. NO.	DATE	DRAWN	CHECKED	ENGR. APPROVAL	DESCRIPTION	FILM
R		4-4-02	J LYNCH/KDL	R KREKEL	D.G.T.	REVISED TO INCORPORATE EC 325236 R/2	
S		4-22-02	J LYNCH/KDL	R KREKEL	D.G.T.	REVISED TO INCORPORATE EC 333382 R/2, EC 333383 R/0 AND EC 167084 R/1	
T		5-1-03	K. LOWE	R KREKEL	T.M.	REVISED TO INCORPORATE EC 340449 R/0	
U		11-4-03	R KREKEL	K. LOWE	D.G.T.	REVISED TO INCORPORATE EC 345176 R/0	
V		8-18-04	K. LOWE	R KREKEL	D.G.T.	REVISED TO INCORPORATE EC 350247 R/0	
G	K-2999	8-19-84			S.K.	REV. FOR CONSTRUCTION, SPEC. K-2999, DCA-BY-1, SL-1	X
G		11-02-84				TRANSFERRED TO IPO	

PATRICK A. NEVINS 62-36880 REGISTERED PROFESSIONAL ENGINEER OF ILLINOIS

DRAWN	NONE	SCALE
CHECKED	4-20-79	DATE
ENGINEER	4-28-79	DATE
APPROVED	4-24-79	DATE

PROJECT NUMBER 4536

SINGLE LINE DIAGRAM
PART 1
CLINTON POWER STATION UNIT 1
CLINTON, ILLINOIS

SARGENT & LUNDY ENGINEERS CHICAGO

DRAWING NO. E02-1AP01 REV. U
SHEET 001 OF —

COMPUTER DWG ▲ DO NOT REVISE MANUALLY

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E02-1AP04-001

4160V ESS SWITCHGEAR RELAY SETTINGS

SERVICE	BKR. OR CUB. NO.	HP OR KVA	CKT. F.L.I. (AMPS)	TRANSF. THRU FAULT CURRENT (AMPS)		RELAY IDENTIFICATION: CT RATIO	MFR.	TYPE	MODEL OR STYLE NO.	RANGE: TIME O/C	H.D. INST.	NORM. INST.	SETTING: TAP	PRIM AMPS		TD	TEST AMPS	TIME SEC.	HD. INST.	PRIM AMPS		NORM INST.	PRIM AMPS		REMARKS
MAIN FEED (RAT 1) TO 4160V ESS BUS 1A1	252-201A1	—	—	27000	PHASE	800-5	W	CO-2	1456C05A03	1-12	—	—	12	1920	—	10	30	1.3	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
					GROUND	800-5	W	CO-2	1456C05A01	.5-2.5	—	—	.5	80	—	10	2	.75	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
MAIN FEED (RAT 1) TO 4160V ESS BUS 1B1	252-201B1	—	—	27000	PHASE	800-5	W	CO-2	1456C05A03	1-12	—	—	12	1920	—	10	30	1.3	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
					GROUND	800-5	W	CO-2	1456C05A01	.5-2.5	—	—	.5	80	—	10	2	.75	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
MAIN FEED (RAT 1) TO 4160V ESS BUS 1C1	252-201C1	—	—	27000	PHASE	1200-5	GE	IFC 51A	#121FC51AD1A	1-12	—	—	12	2880	—	3½	30	2.0	—	—	—	—	—	—	
					GROUND	1200-5	GE	IFC 51A	#121FC51AD2A	.5-4	—	—	.5	120	—	1½	2	.6	—	—	—	—	—	—	
RESERVE FEED (ERAT 1) TO 4160V ESS BUS 1A1	252-221A1	—	—	29000	PHASE	800-5	W	CO-2	1456C05A03	1-12	—	—	12	1920	—	10	30	1.3	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
					GROUND	800-5	W	CO-2	1456C05A01	.5-2.5	—	—	.5	80	—	10	2	.75	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
RESERVE FEED (ERAT 1) TO 4160V ESS BUS 1B1	252-221B1	—	—	29000	PHASE	800-5	W	CO-2	1456C05A03	1-12	—	—	12	1920	—	10	30	1.3	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
					GROUND	800-5	W	CO-2	1456C05A01	.5-2.5	—	—	.5	80	—	10	2	.75	—	—	—	—	—	—	1A SINGLE TAP ICS UNIT
RESERVE FEED (ERAT 1) TO 4160V ESS BUS 1C1	252-221C1	—	—	29000	PHASE	1200-5	GE	IFC 51A	#121FC51AD1A	1-12	—	—	12	2880	—	3½	30	2.0	—	—	—	—	—	—	
					GROUND	1200-5	GE	IFC 51A	#121FC51AD2A	.5-4	—	—	.5	120	—	1½	2	.6	—	—	—	—	—	—	
					PHASE																				
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6900V AND 4160V BUS AND FEED UNDERVOLTAGE RELAY SETTINGS

SERVICE	RELAY DESCRIPTION	RELAY NO.	RELAY TYPE	MODEL OR STYLE NUMBER	CASE SIZE	CT AND/OR PT RATIO	RELAY CHARACTERISTICS	RELAY SETTINGS	TEST POINT: TEST VOLT	TEST POINT: TIME (SEC)	REMARKS
6900V BUS 1A UV RELAY	UNDERVOLTAGE RELAY	527-51A	W CV-2	1454C77A01	FT-11	7200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 93V T.D. 2	0 50	2.2 3.2	0.2A SINGLE TAP ICS UNIT NOTE 4
6900V BUS 1B UV RELAY	UNDERVOLTAGE RELAY	527-51B	W CV-2	1454C77A01	FT-11	7200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 93V T.D. 2	0 50	2.2 3.2	0.2A SINGLE TAP ICS UNIT NOTE 4
4160V BUS 1A UV RELAY	UNDERVOLTAGE RELAY	227-21A	W CV-2	1875506	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 93V T.D. 2	0 50	2.2 3.2	0.2A SINGLE TAP ICS UNIT NOTE 4
4160V BUS 1B UV RELAY	UNDERVOLTAGE RELAY	227-21B	W CV-2	1875506	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 93V T.D. 2	0 50	2.2 3.2	0.2A SINGLE TAP ICS UNIT NOTE 4
4160V ESS BUS 1A1 UV RELAY (FIRST LEVEL)	UNDERVOLTAGE RELAY	227-21A1	W CV-2	1454C77A01	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 82V T.D. 2	0 44	2.2 3.2	0.2A SINGLE TAP ICS UNIT
RAT 1 FEED TO 4160V ESS BUS 1A1 UV RELAY	UNDERVOLTAGE RELAY	227-201A1	W CV-2	1454C77A01	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 82V T.D. 2	0 44	2.2 3.2	0.2A SINGLE TAP ICS UNIT
ERAT FEED TO 4160V ESS BUS 1A1 UV RELAY	UNDERVOLTAGE RELAY	227-221A1	W CV-2	1454C77A01	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 82V T.D. 2	0 44	2.2 3.2	0.2A SINGLE TAP ICS UNIT
4160V ESS BUS 1B1 UV RELAY (FIRST LEVEL)	UNDERVOLTAGE RELAY	227-21B1	W CV-2	1454C77A01	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 82V T.D. 2	0 44	2.2 3.2	0.2A SINGLE TAP ICS UNIT
RAT 1 FEED TO 4160V ESS BUS 1B1 UV RELAY	UNDERVOLTAGE RELAY	227-201B1	W CV-2	1454C77A01	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 82V T.D. 2	0 44	2.2 3.2	0.2A SINGLE TAP ICS UNIT
ERAT FEED TO 4160V ESS BUS 1B1 UV RELAY	UNDERVOLTAGE RELAY	227-221B1	W CV-2	1454C77A01	FT-11	4200-120V	120V AC INVERSE TIME CHARACTERISTIC UV RELAY: 55-140V TAPS @ 55, 64, 70, 82, 93, 105, 120 & 140V	SET @ 82V T.D. 2	0 44	2.2 3.2	0.2A SINGLE TAP ICS UNIT
4160V ESS BUS 1C1 UV RELAY (FIRST LEVEL)	UNDERVOLTAGE RELAY	227-1C1	GE NGV	12NGV13B21A	S-1	4200-120V	120V AC. INSTANTANEOUS UV RELAY 70-100V	NOTE 2 SET TO DROP OUT @ 72V	0	0.018 MAX	2A SINGLE TAP TARGET UNIT NOTE 1
RAT 1 FEED TO 4160V ESS BUS 1C1 UV RELAY	UNDERVOLTAGE RELAY	227-201C1	GE NGV	12NGV13B21A	S-1	4200-120V	120V AC. INSTANTANEOUS UV RELAY 70-100V	SET TO DROP OUT @ 72V	0	0.018 MAX	2A SINGLE TAP TARGET UNIT NOTE 1
ERAT FEED TO 4160V ESS BUS 1C1 UV RELAY	UNDERVOLTAGE RELAY	227-221C1	GE NGV	12NGV13B21A	S-1	4200-120V	120V AC. INSTANTANEOUS UV RELAY 70-100V	SET TO DROP OUT @ 72V	0	0.018 MAX	2A SINGLE TAP TARGET UNIT NOTE 1
4160V ESS BUS 1A1 UV RELAY (SECOND LEVEL)	OVER/ UNDERVOLTAGE RELAY	227-21A1-2	ABB 27N	410T6375-HF-L	410T	4200-120V	INSTANTANEOUS OVER/UNDERVOLTAGE RELAY 70-120V CONTINUOUSLY ADJUSTABLE RANGE	SET TO PICKUP @ 117.52V ±.04V SET TO DROPOUT @ 116.69V ±.04V			NOTE 2 & 3
4160V ESS BUS 1A1 UV RELAY (SECOND LEVEL)	OVER/ UNDERVOLTAGE RELAY	227-21A1-2	ABB 27N	410T6375-HF-L	410T	4200-120V	INSTANTANEOUS OVER/UNDERVOLTAGE RELAY 70-120V CONTINUOUSLY ADJUSTABLE RANGE	SET TO PICKUP @ 117.66V ±.04V SET TO DROPOUT @ 116.83V ±.04V			NOTE 2 & 3
4160V ESS BUS 1B1 UV RELAY (SECOND LEVEL)	OVER/ UNDERVOLTAGE RELAY	227-21B1-2	ABB 27N	410T6375-HF-L	410T	4200-120V	INSTANTANEOUS OVER/UNDERVOLTAGE RELAY 70-120V CONTINUOUSLY ADJUSTABLE RANGE	SET TO PICKUP @ 117.52V ±.04V SET TO DROPOUT @ 116.69V ±.04V			NOTE 2 & 3
4160V ESS BUS 1B1 UV RELAY (SECOND LEVEL)	OVER/ UNDERVOLTAGE RELAY	227-21B1-2	ABB 27N	410T6375-HF-L	410T	4200-120V	INSTANTANEOUS OVER/UNDERVOLTAGE RELAY 70-120V CONTINUOUSLY ADJUSTABLE RANGE	SET TO PICKUP @ 117.66V ±.04V SET TO DROPOUT @ 116.83V ±.04V			NOTE 2 & 3
4160V ESS BUS 1C1 UV RELAY (SECOND LEVEL)	OVER/ UNDERVOLTAGE RELAY	27S-5	ABB 27N	410T6375-HF-L	410T	4200-120V	INSTANTANEOUS OVER/UNDERVOLTAGE RELAY 70-120V CONTINUOUSLY ADJUSTABLE RANGE	SET TO PICKUP @ 117.35V ±.04V SET TO DROPOUT @ 116.52V ±.04V			NOTE 1, 2, & 3
4160V ESS BUS 1C1 UV RELAY (SECOND LEVEL)	OVER/ UNDERVOLTAGE RELAY	27S-6	ABB 27N	410T6375-HF-L	410T	4200-120V	INSTANTANEOUS OVER/UNDERVOLTAGE RELAY 70-120V CONTINUOUSLY ADJUSTABLE RANGE	SET TO PICKUP @ 117.49V ±.04V SET TO DROPOUT @ 116.66V ±.04V			NOTE 1, 2, & 3
TIMER ASSOCIATED WITH 227-1C1	TIMING RELAY	62S1/ 62S2	GE SAM	12SAM11B22A	S-1	—	TIMING RELAY 0.05-3 SEC ADJ RANGE 48/125/250VDC	2.5 SEC, ± 0.075 SEC			TARGET NOT USED
TIMER ASSOCIATED WITH 227-21A1-2	TIMING RELAY	227X2-21A1-2	W TD-5	1520F55A08	FT-11	—	TIMING RELAY 1.5-30 SEC. ADJ. RANGE 48/125VDC	14.9 SEC, ± 0.5 SEC			TARGET NOT USED
TIMER ASSOCIATED WITH 227-21B1-2	TIMING RELAY	227X2-21B1-2	W TD-5	1520F55A08	FT-11	—	TIMING RELAY 1.5-30 SEC. ADJ. RANGE 48/125VDC	14.9 SEC, ± 0.5 SEC			TARGET NOT USED
TIMER ASSOCIATED WITH 227-1C1-2	TIMING RELAY	62S5	AGASTAT TR	ETR14030 C2004002	—	—	TIMING RELAY 2-60 SEC. ADJ. RANGE 125VDC	14.9 SEC, ± 0.5 SEC			—

"I"

NOTE:

* USE 0.2A TAP OF TARGET & SEAL IN UNIT

TIME DIAL SETTINGS ARE NOMINAL. THE TEST POINT TIME SHALL HAVE THE FOLLOWING TOLERANCES:

(a) ±5% FOR WESTINGHOUSE RELAYS, TYPE CO-2, CO-4, CO-5, CO-6, CO-8, CO-9, CO-11, COM-5, CW, CV-2 & CVQ.
(b) ±7% FOR GENERAL ELECTRIC RELAYS TYPE IAC, IFC & IJCV.
(c) ±10% FOR GENERAL ELECTRIC RELAYS TYPE IAV & GGP.

NOTE 1
227-1C1 CONSISTS OF 4 RELAYS (27S1, 27S2, 27S3 & 27S4)
227-201C1 CONSISTS OF 2 RELAYS (27N1 & 27N2)
227-221C1 CONSISTS OF 2 RELAYS (27E1 & 27E2)
RELAYS 27S5 AND 27S6 ARE PART OF 227-1C1-2

NOTE 2
SEE ASSOCIATED TIMERS ON THIS DWG. FOR TIME SETTINGS.

NOTE 3
THE RELAY "FIXED TAP SETTINGS" ARE: PICKUP VOLTAGE 120 V, TIME DIAL 0.1 & % DROPOUT 99. RELAY IS TO BE TESTED TO VERIFY THE PICKUP AND DROPOUT VOLTAGE SETTINGS AS INDICATED ARE WITHIN ±0.04 V TOLERANCE. THE DROPOUT DELAY TIMER IS TO BE SET TO MINIMUM. THE RELAY TIMER IS TO BE TESTED TO CONFIRM IT DROPS OUT IN LESS THAN 0.2 SECONDS.

NOTE 4
ENSURE CV-2 RELAY IS CONFIGURED FOR NON ICS CONTACT USAGE PER RELATED E02 DRAWINGS BY REMOVAL OF INTERNAL JUMPER.

ERAT (0AP03E) VOLTAGE REGULATING RELAY CONTROL SETTINGS

MODEL OR STYLE NUMBER	PT RATIO	RELAY CHARACTERISTICS	RELAY SETTINGS
PRIMARY RELAY BECKWITH TAPCHANGER CONTROL M-0067E	2400-120V	VOLTAGE CENTER OF BAND: 105-135V TOTAL BANDWIDTH: 1.0-6.0V TIME DELAY: 0-120 SEC. LINE DROP COMPENSATOR: A) 24V COMP. FOR 0.2A INPUT IN PHASE WITH INPUT VOLTAGE. B) 24V COMP. FOR 0.2A INPUT AT A PHASE ANGLE OF +/- 90°	VOLTAGE CENTER OF BAND: 120V(+/- 0.5V) BANDWIDTH: 2.7V(+/- 0.58V) TIME DELAY: 7.0 SEC(+/- 2 SEC). A) RESISTANCE (R) = 0V B) REACTANCE (X) = 1V C) DIRECT/REVERSE SWITCH: DIRECT D) TEST/OPERATE SWITCH: OPERATE
VOLTAGE BACKUP RELAY: BECKWITH M-0329A LTC BACKUP CONTROL	2400-120V	BANDCENTER: 100-140V BANDWIDTH: 6V TO 24V FOR 120V AC FIXED DEADBAND: 1, 2, 3 OR 4 V TIME DELAY: 1-30 SEC.	BANDCENTER: 119.5V(+/- 1.2V) BANDWIDTH: 6V(+/- 1.2V) FIXED DEADBAND: 2V(+/-1.23V) TIME DELAY: 5 SEC. BLOCKING CONTACTS TIME DELAY: 0.2 SEC. ALARM ACTIVATION TIME DELAY: 3 MIN.

REFERENCE: CALCULATION 19AN-2, REV.8, AND 19AN-19

REV	DATE	DESCRIPTION	PREP.	REVR.	APPR.
I	EDSF	EC 345565	EDSF	EDSF	EDSF

4160V AND 6900V SWGR
RELAY SETTINGS
CLINTON POWER STATION UNIT 1
CLINTON, ILLINOIS

Exelon Nuclear
Clinton Station Unit 1

NUCLEAR SAFETY RELATED EQUIPMENT IS SHOWN ON THIS DRAWING

SCALE : NONE
DATE :
DRAWN BY :
ORG. BY : 2040

E02-1AP04

SHEET NUMBER: 001 | SIZE: F | E02

E02-1AP04

DIESEL GENERATOR 1A (DIVISION 1)

SERVICE	RELAY DESCRIPTION	RELAY NO.	RELAY TYPE	MODEL OR STYLE NUMBER	CASE SIZE	CT AND/OR PT RATIO	RELAY CHARACTERISTICS	RELAY SETTINGS	TEST REQUIREMENTS	REMARKS
GENERATOR 1A DIFFERENTIAL	HIGH SPEED DIFFERENTIAL	87	W SA-1	290B225A10	FT-32	800-5A	0.14A MIN. TRIP	NONE REQUIRED		
GENERATOR 1A LOSS-OF-FIELD	LOSS-OF-EXCITATION	40	GE CEH	12CEH51A1A	M1	4200-120V 800-5A	60 HZ 0-4 ohm OFFSET, 5-50 ohm DIAMETER	OFFSET = 1.0 ohm (L=0, H=1.0) ** RESTRAINT= 46% (I_U=6, I_L=40)	SEE NOTE# 1A	OPERATION BLOCKED DURING LOCA
GENERATOR 1A NEUTRAL GROUND	TIME DELAY OVERVOLTAGE	59G	GE IAV510	12IAV51D1A	S1	4160-240V	TIME DIAL RANGE 1-10 PICKUP TAPS A-16V, B-24V, C-40V, D-64V	TAP A-16V, T.D. 5 **	30V 2.5 SEC	OPERATION BLOCKED DURING LOCA
GENERATOR 1A OVERCURRENT	VOLTAGE RESTRAINT TIME OVERCURRENT	51V	GE IJCV OR IFCV	12IJCV51A13A OR 12IFCV51AD1A	S1(IJCV) C1(IFCV)	4200-120V 800-5A	RATED 115V(IJCV), 120V(IFCV) TIME OVERCURRENT 4-16A WITH 100% V(IJCV) TIME OVERCURRENT 2-16A WITH 100% V(IFCV)	TAP 10A, T.D. 3 **	SEE NOTE# 2A	OPERATION BLOCKED DURING LOCA. SEE NOTE 8.
GENERATOR 1A ANTI-MOTORING	POWER DIRECTIONAL	32	GE GGP	12GGP53C1A	M2	4200-120V 800-5A	MAIN UNIT ADJUSTABLE SETTING 120V, 10-40 mA TIME DIAL RANGE .5-10	SETTING TD= 5½ (15 SEC DELAY) **	SEE NOTE# 3B	OPERATION BLOCKED DURING LOCA
GEN 1A BREAKER CLOSE PERMISSIVE	UNDERVOLTAGE	27	W CV-2	1454C77A01	FT-11	4200-120V	55-140V RANGE SHORT TIME UNDERVOLTAGE	TAP 105V, TIME DIAL 1 **	SEE NOTE# 4A	RELAY MODIFIED WITH A T-COIL CURRENT LIMITING 4000 Ω RESISTOR. SEE K2968-0004

"W"
EC 167078

DIESEL GENERATOR 1B (DIVISION 2)

ECN 31948

SERVICE	RELAY DESCRIPTION	RELAY NO.	RELAY TYPE	MODEL OR STYLE NUMBER	CASE SIZE	CT AND/OR PT RATIO	RELAY CHARACTERISTICS	RELAY SETTINGS	TEST REQUIREMENTS	REMARKS
GENERATOR 1B DIFFERENTIAL	HIGH SPEED DIFFERENTIAL	87	W SA-1	290B225A10	FT-32	800-5A	0.14A MIN. TRIP	NONE REQUIRED		
GENERATOR 1B LOSS-OF-FIELD	LOSS-OF-EXCITATION	40	GE CEH	12CEH51A1A	M1	4200-120V 800-5A	60 HZ D-4 ohm OFFSET, 5-50 ohm DIAMETER	OFFSET = 1.5 ohm (L=2.5, H=4.0) ** RESTRAINT= 54% (I_U=4, I_L=30)	SEE NOTE# 1A	OPERATION BLOCKED DURING LOCA
GENERATOR 1B NEUTRAL GROUND	TIME DELAY OVERVOLTAGE	59G	GE IAV510	12IAV51D1A	S1	4160-240V	TIME DIAL RANGE 1-10 PICKUP TAPS A-16V, B-24V, C-40V, D-64V	TAP A-16V, T.D. 5 **	30V 2.5 SEC	OPERATION BLOCKED DURING LOCA
GENERATOR 1B OVERCURRENT	VOLTAGE RESTRAINT TIME OVERCURRENT	51V	GE IJCV OR IFCV	12IJCV51A13A OR 12IFCV51AD1A	S1(IJCV) C1(IFCV)	4200-120V 800-5A	RATED 115V(IJCV), 120V(IFCV) TIME OVERCURRENT 4-16A WITH 100%V(IJCV) TIME OVERCURRENT 2-16A WITH 100%V(IFCV)	TAP 10A, T.D. 3 **	SEE NOTE# 2A	OPERATION BLOCKED DURING LOCA SEE NOTE 8
GENERATOR 1B ANTI-MOTORING	POWER DIRECTIONAL	32	GE GGP	12GGP53C1A	M2	4200-120V 800-5A	MAIN UNIT ADJUSTABLE SETTING 120V, 10-40 MA TIME DIAL RANGE .5-10	SETTING TD= 5½ (15 SEC DELAY) **	SEE NOTE# 3B	OPERATION BLOCKED DURING LOCA
GEN. 1B BREAKER CLOSE PERMISSIVE	UNDERVOLTAGE	27	W CV-2	1454C77A01	FT-11	4200-120V	55-140V RANGE SHORT TIME UNDERVOLTAGE	TAP 105V, TIME DIAL 1 **	SEE NOTE# 4A	RELAY MODIFIED WITH A T-COIL CURRENT LIMITING 4000 Ω RESISTOR. SEE K2968-0004

"W"
EC 167079

DIESEL GENERATOR 1C (DIVISION 3)

SERVICE	RELAY DESCRIPTION	RELAY NO.	RELAY TYPE	MODEL OR STYLE NUMBER	CASE SIZE	CT AND/OR PT RATIO	RELAY CHARACTERISTICS	RELAY SETTINGS	TEST REQUIREMENTS	REMARKS
GENERATOR 1C DIFFERENTIAL	HIGH SPEED HIGH IMPEDANCE	28T DG1C	GE PVD	12PVD21B1A	M1	800-5A	150V CONTINUOUS, 1 THYRITE STACK, 75-500V VOLTAGE UNIT RANGE, 2-60A CURRENT UNIT	VOLTAGE UNIT (87L) = 75V CURRENT UNIT (87H) = 2A **	SEE NOTES# 5A	
GENERATOR 1C LOSS OF FIELD	LOSS OF EXCITATION	240 DG1C	GE CEH	12CEH51A1A	M1	4200-120V 800-5A	115V, 60HZ, 125/250V AUX UNIT VOLTAGE 5-50 ohm DIAMETER, 0-4 ohm OFFSET	OFFSET 2 ohm IL=0.5, H=2.5) RESTRAINT 28% (I_U=6, I_L=20) **	SEE NOTES# 5B	NOTE 1
GENERATOR 1C OVERCURRENT	TIME OVERCURRENT VOLT RESTRAINT	251V DG1C	GE IJCV OR IFCV	12IJCV51B21A OR 12IFCV51AD1A	S1(IJCV) C1(IFCV)	4200-120V 800-5A	120V RESTRAINT, 4-16A TOC UNIT AT 100% RESTRAINT (IJCV), 2-16A TOC UNIT (IFCV) 4-16A INSTANT. UNIT (IJCV ONLY)	TOC TAP AT 8A, T.D. 8 IOC UNIT NOT **	SEE NOTES# 5C	NOTE 3
GENERATOR 1C OVERCURRENT	TIME OVERCURRENT MEDIUM INVERSE	251 DG1C	GE IAC	12IAC57A2A	S1	800-5A	1.5-6A TOC RANGE TAPS AT 1.5,2,2.5,3,4,5 & 6A	TOC TAP AT 3A, T.D 3 1/2 ** TEST AMP→9A, TRIP TIME 9 1/2±0.1 SEC.	SEE NOTES# 5D	NOTE 4
GENERATOR 1C ANTI-MOTORING	POWER DIRECTIONAL	232 DG1C	GE GGP	12GGP53C1A	M2	4200-120V 800-5A	60HZ, 120, 5A RATING: MAIN UNIT ADJUST. SETTING @ 120V 10.0-40.0 mA TIMING UNIT 1.5 TO 30 SEC. ADJUSTABLE	SETTING TD= 5½ (15 SEC DELAY) **	SEE NOTES# 5E	NOTE 1
GENERATOR 1C NEUTRAL GROUND	TIME DELAY OVERVOLTAGE RELAY	259 DG1C	GE IAV	12IAV51K1A	S1	4160V-120V	67V RATED, 60HZ, 5.4-20V TAP RANGE TAPS AT 5.4,7.5,12.5,20V	TAP 5.4 TIME DIAL 6 **	SEE NOTES# 5F	NOTE 2
GENERATOR 1C UNDERVOLTAGE RELAY	INSTANTANEOUS VOLTAGE RELAY	22T DG1C	GE NGV	12NGV13B21A	S1	4200-120V	120V, 60HZ RATED DROPOUT VOLTAGE CONTINUOUSLY ADJUSTABLE BETWEEN 70-100V	SET TO DROPOUT AT 100V FOR VOLTAGE DROP 150V→0 TMAX = 18 MSEC	SEE NOTES# 5G	NOTES 5, 7, 8
AUX. TIMER FOR 227DG1C	AUX. TIMER TO PU	K54X	AGASTAT	ETR14D3BC 2004002		—	CONTINUOUSLY ADJUSTABLE .55-15 SEC.	.55 SEC.	N/A	NOTES 6, 7

"W"
EC 167080

"W"
EC 167078
EC 167079

TEST REQUIREMENT NOTES

(A) FOR TEST REQUIREMENTS REFER TO K2861-00026 INSTRUCTION MANUAL ACCEPTABLE ANGLE OF MAX TORQUE IS 90° (± 3°) CURRENT LEADING VOLTAGE

2A) TEST #1 - TEST VOLTAGE-115 V (IJCV), 120V (IFCV)
TEST AMP - 20A
TEST TIME - 1.1 SECONDS (SECS)
TEST #2 - TEST VOLTAGE-0V
TEST CURRENT-16A
TEST TIME-0.9 SECS (IJCV)
0.93 SECS (IFCV)

3A) DELETED

3B) FOR GENERATOR ANTI-MOTORING (TYPE GE GGP) RELAY
TIMING UNIT: -TEST VOLTAGE 120V.
TEST TIME: -DIV 1 (≥14, ≤15 SEC.) DIV 2 (≥14, ≤15) SEC.
-MIN. PICK-UP 60 VAC ±3.6V.
MAIN UNIT: -PICK-UP CURRENT 40.0 mA ±5%
AT 120 VAC

4A) THE RELAY CONTACT SHALL DROPOUT AS THE VOLTAGE IS INCREASED BETWEEN A VALUE OF 106V AND 108V.

5A) FOR GENERATOR DIFF RELAY (TYPE GE-PVD) REFER TO K-2801-0175 BK 2 INSTRUCTION MANUAL

5B) FOR GENERATOR LOSS OF FIELD RELAY (TYPE GE-CEH) REFER TO K-2801-0172 VOL 2 BK 1 INSTRUCTION MANUAL ACCEPTABLE ANGLE OF MAX TORQUE IS 90° (±3°) CURRENT LEADING VOLTAGE

TEST REQUIREMENT NOTES (CONT'D)

5C) FOR GENERATOR OVERCURRENT (TYPE GE-IJCV) RELAY

TEST #1
TEST VOLTAGE-115V (IJCV)
120V (IFCV)
TEST CURRENT-20A
TEST TIME-2.1 SECS

TEST #2
TEST VOLT-0V
TEST CURR-8A
TEST TIME-4.2 SECS (IJCV)
4.0 SECS (IFCV)

5D) GENERATOR OVERCURRENT (TYPE GE-IAC) RELAY
TEST CURRENT-9 A TEST TIME - 9.5 SECS

5E) FOR GENERATOR ANTI-MOTORING (TYPE GE GGP) RELAY
TIMING UNIT: -TEST VOLTAGE 120V.
TEST TIME ≥14 & ≤15 SECS.
-MIN. PICK-UP 60 VAC ± 3.6V.
MAIN UNIT: -PICK-UP CURRENT 40.0mA ±5%
AT 120 VAC

5F) FOR GENERATOR NEUTRAL GROUND (TYPE GE-IAV) RELAY
TEST VOLTAGE-30V
TEST TIME 2.5 SECS

5G) FOR GENERATOR UNDERVOLTAGE RELAY (TYPE GE-NGV)
FOR VOLTAGE DROP 150V→0
TMAX = 18 M SECS.

(NOTES CONT'D ABOVE RIGHT)

TEST REQUIREMENT NOTES (CONT'D)

6 TIME DIAL SETTINGS ARE NOMINAL.
THE TEST POINT TIME SHALL HAVE THE FOLLOWING TOLERANCES
A ±5% FOR WESTINGHOUSE RELAYS, TYPE CO-2, CO-4, CO-5, CO-6, CO-8, CO-9, CO-11, COM-5, CW, CV-2, & CVQ
B ±7% FOR GENERAL ELECTRIC RELAYS TYPE IAC, IFCV & IJCV.
C ±10% FOR GENERAL ELECTRIC RELAYS TYPE IAV & GGP
THE ABOVE TOLERANCES ARE NOT APPLICABLE WHEN SPECIFIC TOLERANCES ARE PROVIDED IN SPECIFIC TEST REQUIREMENTS.

7. THE IJCV RELAYS WERE MANUFACTURED WITH BOTH 115V AND 120V RATINGS BUT BOTH HAVE THE SAME INSTRUCTION BOOKLET (GEH-2029A). TEST/CALIBRATE THE IJCV RELAYS AT 115V.

8. ACTUALLY 3 RELAYS (51V-1, 51V-2 & 51V-3) MAINTAIN SAME MODEL FOR ALL 3 RELAYS, EITHER IJCV OR IFCV.

J. S. STEELE 62 36980 REGISTERED PROFESSIONAL ENGINEER OF ILLINOIS

NOTES:

** USE 0.2A TAP ON ISC OR SI UNIT

NOTES: APPLICABLE ONLY FOR DIESEL GENERATOR 1C

1) TRIP OPERATION OF THE RELAY IS BLOCKED DURING LOCA.
2) RELAY IS USED FOR ALARM ONLY.
3) TRIP OPERATION AFTER 0.5 SECOND TIME DELAY-TRIP OPERATION BLOCKED DURING LOCA.
ACTUALLY 3 RELAYS (K35A, K35B & K35C) MAINTAIN SAME MODEL FOR ALL 3 RELAYS, EITHER IJCV OR IFCV.
4) OPERATES ONLY WHEN DIESEL GENERATOR RUNNING IN PARALLEL WITH MAIN OR RESERVE SOURCE. ALARMS AND TRIPS MAIN AND RESERVE SOURCE BREAKERS.
5) RELAY USED TO PERMIT THE DG BREAKER CLOSING.
6) AUX. TIMER MODEL NO. PROVIDED VERBALLY BY G.E.
7) SETTING IS BASED ON DESIGN CHANGES AUTHORIZED UNDER DCA DG-3.
8) TARGET SEAL-IN COIL NOT USED

REFERENCE CALCULATION 19AN-14 REV.5 A 19AN-17 REV.2

NUCLEAR SAFETY RELATED
EQUIPMENT IS SHOWN ON THIS DRAWING
(FOR SAFETY CLASSIFICATION SEE EQUIPMENT, VALVE, OR INSTRUMENT LISTS)

S&L ECAD FILE: CLIES8.16

DRAWING RELEASE RECORD

REV.	DATE REL'D.	PREPARED	REVIEWED	APPROVED	PURPOSE	FILM
W	10-03-01	J LYNCH	R KREKEL	M WILKINSON	REVISED TO INCORPORATE ECs 167078, 167079 & 167080	
G	6-2-93	TSS/ J SENDZIK	D HAWK	J EMMERT	REVISED PER D.46 TO INCORPORATE DRAFTING ID 07018	
H	6-28-93	TSS/ J SENDZIK	D HAWK	J EMMERT	REVISED TO INCORPORATE ECN 27948	
J	8-26-93	TSS/ J SENDZIK	D HAWK	J EMMERT	REVISED PER D.46 TO INCORPORATE DRAFTING ID 07046, ECN 27998 AND 28001	
K	10-27-93	TSS/ J SENDZIK	D HAWK	J EMMERT	REVISED PER D.46 TO INCORPORATE DRAFTING ID 07084	
L	01-06-94	EAD/ RH KRESIN	D HAWK	JM EMMERT	REVISE PER D.46 TO INCORPORATE DRAFTING ID 07110.	
M	2-16-94	TSS/ RH KRESIN	D HAWK	JM EMMERT	REVISE PER D.46 TO INCORPORATE DRAFTING ID 07134.	
N	5-6-94	TSS/SOBOTTKA	D HAWK	J EMMERT	REVISED PER D46 TO INCORPORATE DRAFTING ID 07169	
P	10-7-94	TSS/SOBOTTKA	D HAWK	J EMMERT	REVISED TO INCORPORATE ECN 28630 AND 28631	X
R	7-19-95	MEC/LM	JOHN EMMERT	T.O. WIGGINS	REVISED TO INCORPORATE D.46 07256	
S	9-10-97	KDL/KBT/RAK/KC	C.R.SMAIL	T.O. WIGGINS	REVISED TO INCORPORATE ECNs 29297, 29298, 29303 & D.46 #07366, AND CLEANUP SCANNED FILE	
T	01-11-99	R SAHA	R. KREKEL	R. KREKEL	REVISED TO INCORPORATE D.46 07648 AND D.43 PROCEDURE	
U	04-24-00	R KREKEL	J.A.ZUMBAHLEN	J.A.ZUMBAHLEN	REVISED TO INCORPORATE ECN 31948 & ECN 31949.	
V	05/04/00	J.A.ZUMBAHLEN	K. NELSON	K. NELSON	REVISED TO INCORPORATE ECN 31941.	

THOMAS M. McCAULEY REGISTERED PROFESSIONAL ENGINEER OF ILLINOIS

SCALE: NONE
PROJECT NUMBER: 7510-40 7665

DIESEL GENERATOR 1A, 1B & 1C
RELAY SETTINGS
CLINTON POWER STATION UNIT 1
CLINTON ILLINOIS

SARGENT & LUNDY ENGINEERS CHICAGO

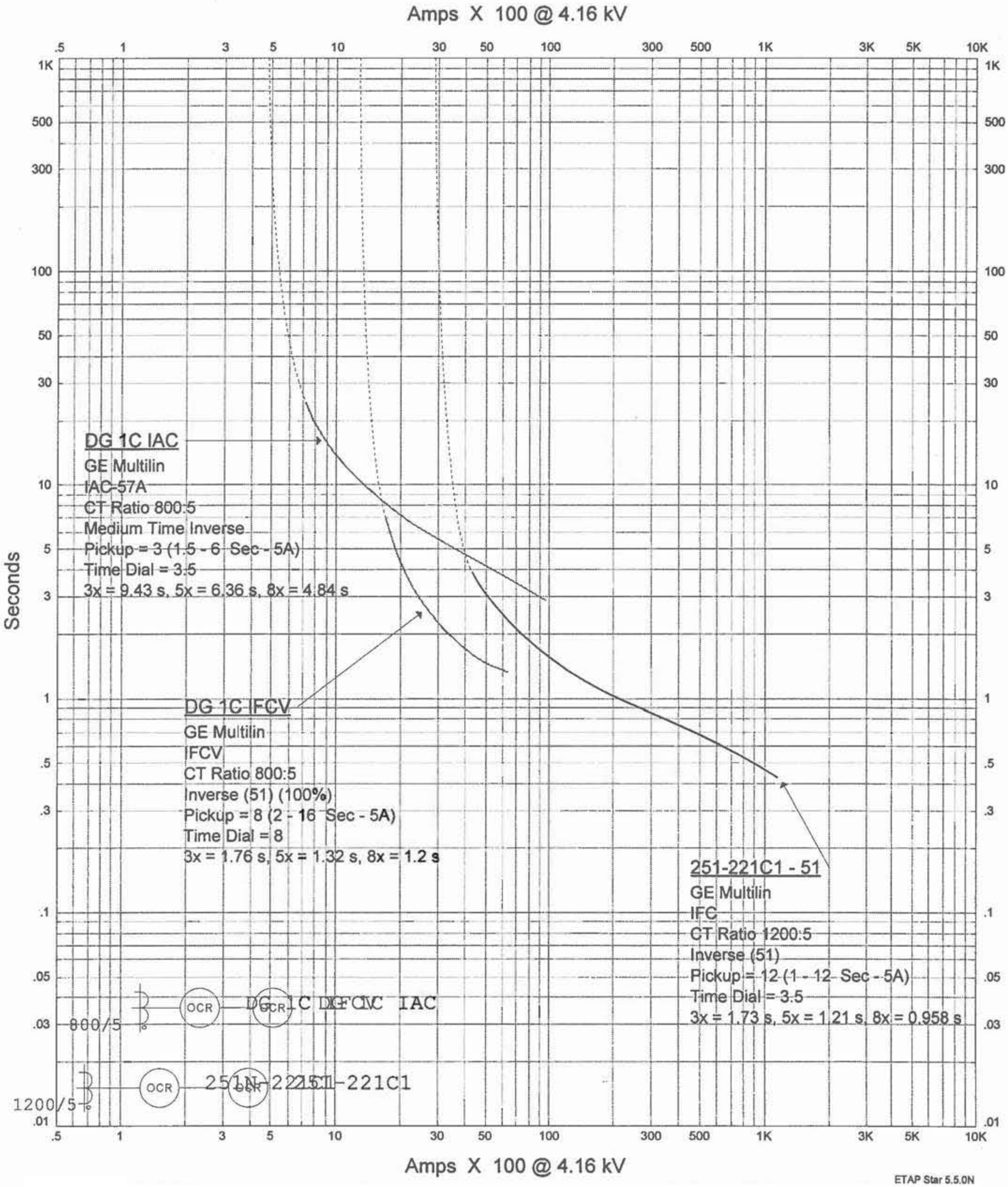
DRAWING NO: E02-1AP04 REV: W

SHEET 01 OF —

COMPUTER DWG ▲ DO NOT REVISE MANUALLY

Attachment 3
Clinton Power Station Current Versus Time Overcurrent Relay Settings

Plot of the Clinton Power Station Division 3 Overcurrent Relay Settings (Amps versus Time)



Amps X 100 @ 4.16 kV
Seconds
DG 1C IAC
GE Multilin
IAC-57A
CT Ratio 800:5
Medium Time Inverse
Pickup = 3 (1.5 - 6 Sec - 5A)
Time Dial = 3.5
3x = 9.43 s, 5x = 6.36 s, 8x = 4.84 s
DG 1C IFCV
GE Multilin
IFCV
CT Ratio 800:5
Inverse (51) (100%)
Pickup = 8 (2 - 16 Sec - 5A)
Time Dial = 8
3x = 1.76 s, 5x = 1.32 s, 8x = 1.2 s
251-221C1 - 51
GE Multilin
IFC
CT Ratio 1200:5
Inverse (51)
Pickup = 12 (1 - 12 Sec - 5A)
Time Dial = 3.5
3x = 1.73 s, 5x = 1.21 s, 8x = 0.958 s
800/5
OCR
1200/5
251N-221C1
251-221C1
ETAP Star 5.5.0N

Attachment 4
Markup of Existing Technical Specifications Pages

Clinton Power Station, Unit 1

Facility Operating License No. NPF-62

License Amendment Request to Remove Operating Mode Restrictions for Performing Division 3 Emergency Diesel Generator Surveillance Testing

MARKUP OF EXISTING TECHNICAL SPECIFICATIONS PAGES

3.8-6
3.8-8
3.8-9
3.8-11
3.8-13

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	-------------------NOTE------------------ All DG starts may be preceded by an engine prelube period. --- Verify each DG starts from standby condition and achieves: a. In ≤ 12 seconds, voltage ≥ 4084 V and frequency ≥ 58.8 Hz; and b. Steady state voltage ≥ 4084 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	184 days
SR 3.8.1.8	-----------------NOTE------------------- 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 unit power supply from the normal offsite circuit to the alternate offsite circuit.	24 months

(not applicable to Division 3 AC sources)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

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. (not applicable to the Division 3 DG) 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 ≤12 seconds, 2. energizes auto-connected shutdown loads, 3. maintains steady state voltage ≥ 4084 V and ≤ 4580 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	24 months
		(continued)

SURVEILLANCE REQUIREMENTS (continued)

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 DG auto-starts from standby condition and: a. In ≤ 12 seconds after auto-start and during tests, achieves voltage ≥ 4084 V and frequency ≥ 58.8 Hz; b. Achieves steady state voltage ≥ 4084 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	(not applicable to the Division 3 DG) 24 months
SR 3.8.1.13	------------------NOTE-------------------- Credit may be taken for unplanned events that satisfy this SR. -- Verify each DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except: a. Engine overspeed; b. Generator differential current; and c. Overcrank for DG 1A and DG 1B.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16 (not applicable to the Division 3 DG)	-------------------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 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 loads from offsite power.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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 (not applicable to the Division 3 DG). 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 Divisions 1 and 2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 12 seconds, 2. energizes auto-connected emergency loads, 3. achieves steady state voltage ≥ 4084 V and ≤ 4580 V, 4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	24 months

(continued)

Attachment 5
Markup of Existing Technical Specifications Bases Changes (For Information Only)

Clinton Power Station, Unit 1

Facility Operating License No. NPF-62

License Amendment Request to Remove Operating Mode Restrictions for Performing Division 3 Emergency Diesel Generator Surveillance Testing

MARKUP OF EXISTING TECHNICAL SPECIFICATIONS BASES PAGES
(FOR INFORMATION ONLY)

B 3.3-121
B 3.8-18
B 3.8-21
B 3.8-22
B 3.8-27
B 3.8-30

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.1, LCO 3.5.2, LCO 3.7.2, LCO 3.8.1, and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

The Self Test System may be utilized to perform this testing for those components that it is designed to monitor. Those portions of the solid-state logic not monitored by the Self Test System may be tested at the frequency recommended by the manufacturer, rather than at the specified 24-month Frequency. The frequencies recommended by the manufacturer are based on mean time between failure analysis for the components in the associated circuits.

(except for the Division 3 diesel generator, which can be tested in any MODE)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for unplanned transients if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance.

REFERENCES

1. USAR, Section 5.2.2.

2. USAR, Section 6.3.

3. USAR, Chapter 15.

4. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Part 2," December 1988.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit. The 24 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, 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. Examples of unplanned events may include:

(The Note is not applicable to Division 3 AC Sources)

1) Unexpected operational events which cause the equipment to perform the function specified by this surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject a load equivalent to at least as large as the largest single load while maintaining a specified margin to the overspeed trip.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months is consistent with the refuel cycle recommendations of Regulatory Guide 1.9 (Ref. 16), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. (Note 2 is not applicable to the Division 3 DG) Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (12 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability.

With regard to DG start time, required voltage and frequency values obtained pursuant to this SR, as read from plant indication instrumentation, the specified limit is not considered to be a nominal value with respect to instrument uncertainties. This requires additional margin to be added to the limit to compensate for instrument uncertainties, for implementation in the associated plant procedures (Refs. 17, 18, 19, 22, 23).

The Frequency of 24 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. (Note 2 is not applicable to the Division 3 DG) Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

This Note

(This Note is not applicable to the Division 3 DG)

SR 3.8.1.16 (continued)

This SR is 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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.17

Demonstration of the test mode override is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(8)and ensures that the DG availability under accident conditions is not compromised as the result of testing. Except as clarified below for the Division 3 DG, interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation if an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at rated speed and voltage with the DG output breaker open. These provisions for automatic switchover are required by IEEE-308 (Ref. 14), paragraph 6.2.6(2), as further amplified by IEEE 387, sections 5.6.1 and 5.6.2. (Clarification regarding conformance of the Division 3 DG design to these standards is provided in the USAR, Chapter 8 (Reference 2).)

Automatic switchover from the test mode to ready-to-load operation for the division 3 DG is also demonstrated, as described above, by ensuring that DG control logic automatically resets in response to a LOCA signal during the test mode and confirming that ready-to-load operation is attained (as evidenced by the DG running with the output breaker open). However, with the DG governor initially operating in a "droop" condition during the test mode, operator action may be required to reset the governor for

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

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

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. For load shedding effected via shunt trips that are actuated in response to a LOCA signal (i.e., "ECCS initiation signal"), this surveillance includes verification of the shunt trips (for Divisions 1 and 2 only) in response to LOCA signals originating in the ECCS initiation logic as well as the Containment and Reactor Vessel Isolation and Control System actuation logic. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions. Standby conditions mean that the lube oil is heated by the jacket water and continuously circulated through a portion of the system as recommended by the vendor. Engine jacket water is heated by an immersion heater and circulates through the system by natural circulation. This allowance is not intended to impose a maximum limit on engine temperatures. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems (Note 2 is not applicable to the Division 3 DG). Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)