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10 CFR 50.90
10 CFR 50.59

RS-06-006

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

Quad Cities Nuclear Power Station, Units 1 and 2
Renewed Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Request for License Amendment Regarding Automatic Operation of Transformer Load Tap Changers

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," and 10 CFR 50.59, "Changes, tests, and experiments," Exelon Generation Company, LLC (EGC) requests approval for a change to the Updated Final Safety Analysis Report (UFSAR). The requested change implements the use of automatic load tap changers (LTCs) on transformers that provide offsite power to Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2.

The LTCs are subcomponents of new transformers that are being installed to compensate for potential offsite power voltage fluctuations in order to ensure that acceptable voltage is maintained for safety related equipment. The proposed change requests NRC approval to operate the LTCs in automatic mode. The LTCs will be operated only in the manual mode, which does not require prior NRC approval in accordance with 10 CFR 50.59, until the changes requested herein are approved. Once the proposed changes are approved, operation of the LTCs in automatic mode will be allowed and the UFSAR description of the offsite power sources will be revised to describe the automatic LTC operation. Operation of the LTCs in automatic mode requires NRC approval in accordance with 10 CFR 50.59, since automatic LTC operation creates a possibility for a malfunction of a structure, system, or component important to safety with a different result than any previously evaluated in the UFSAR.

This request is subdivided as follows.

- Attachment 1 provides an evaluation supporting the proposed change.
- Attachment 2 contains the marked-up UFSAR page with the proposed change indicated.

The proposed change has been reviewed by the QCNPS 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 July 25, 2006.

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 by transmitting a copy of this letter and its attachments to the designated State Official.

If you have any questions or require additional information, please contact Mr. David Gullott at (630) 657-2819.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 25th day of January 2006.

Respectfully,

Patrick R. Simpson

Patrick R. Simpson
Manager – Licensing

Attachment 1: Evaluation of Proposed Change
Attachment 2: Marked-up UFSAR Page with Proposed Change

ATTACHMENT 1
Evaluation of Proposed Change

ATTACHMENT 1
Evaluation of Proposed Change

1.0 DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," and 10 CFR 50.59, "Changes, tests, and experiments," Exelon Generation Company, LLC (EGC) requests approval for a change to the Updated Final Safety Analysis Report (UFSAR). The requested change implements the use of automatic load tap changers (LTCs) on the reserve auxiliary transformers (RATs). The RATs provide offsite power to Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2.

The LTCs are subcomponents of new transformers that are being installed to compensate for potential offsite power voltage fluctuations in order to continue to ensure that acceptable voltage is maintained for safety related equipment. Installation of a RAT with the automatic LTC feature is planned for QCNPS Unit 2 during the Spring 2006 refueling outage and for QCNPS Unit 1 during the Spring 2007 refueling outage.

The proposed change requests NRC approval to operate the LTCs in the automatic mode. Both LTCs will be operated only in the manual mode, which does not require prior NRC approval, until the change requested herein is approved. Once the proposed change is approved, operation of the LTCs in automatic mode will be allowed and the UFSAR description of the offsite power sources will be revised to describe the automatic LTC operation. Operation of the LTCs in automatic mode requires NRC approval in accordance with 10 CFR 50.59, since automatic LTC operation creates a possibility for a malfunction of a structure, system, or component important to safety with a different result than any previously evaluated in the UFSAR.

2.0 PROPOSED CHANGE

The proposed UFSAR change adds a discussion of the automatic operation mode of the LTCs. For both QCNPS Units 1 and 2, the current RATs (i.e., transformers TR 12 and TR 22, respectively) will be upgraded with slightly larger capacity transformers that feature a LTC to regulate voltage on the safety related buses. The RATs provide offsite power from the 345 kV transmission system.

To reflect the incorporation of the new RATs and associated LTCs, a change to the QCNPS UFSAR Section 8.3.1.2.2.1, "Reserve Auxiliary Transformer," is proposed. The change to this section adds a discussion of the LTC operation and evaluation of operation in the automatic mode. The UFSAR change markup is provided in Attachment 2.

3.0 BACKGROUND

At QCNPS, power to safety related equipment is provided by two divisions of 4160 V essential service system (ESS) buses. For each unit, one division is normally powered by the unit auxiliary transformer (UAT), which receives its power from the main generator, and the other division is normally powered by the RAT, which receives its power from the offsite transmission system. If power from the UAT is lost, the source of power to the ESS buses is transferred to the RAT. To maintain operability of the offsite power circuits, the minimum required switchyard voltage is approximately 352.9 kV for QCNPS, Unit 1 and approximately 351 kV for QCNPS, Unit 2. These voltages ensure that the voltage is adequate at the ESS buses, under accident loading conditions. The loss of power (LOP) instrumentation monitors the ESS buses, and if

insufficient voltage is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) electrical power sources.

Exelon Energy Delivery (EED) is the transmission system operator for QCNPS. Prior to June 1, 2004, EED maintained a system planning operating guide (SPOG) 2-1 that provided expected actual switchyard voltages at the nuclear stations, based a set of operational contingencies and studies of projected load growth. SPOG 2-1 stated that the expected voltage would be maintained between approximately 103% and 105% of the nominal voltage on the 345 kV system, or 354.1 kV to 362.3 kV. The expected minimum switchyard voltage in SPOG 2-1 did not bound every possible combination of transmission system contingencies. Due to unforeseen changes in generation and load patterns, the actual minimum voltage may have been lower than the expected voltage. A state estimator was used with contingency analysis applications to monitor real-time grid conditions and determine the predicted switchyard voltage following a trip of one of the QCNPS units.

On June 1, 2004, the EED transmission system became part of the Pennsylvania, New Jersey, Maryland (PJM) interconnect network. For transmission planning purposes under the PJM interconnect network, EED maintains transmission system planning criteria to set the maximum voltage and the expected minimum voltage for the transmission system. The transmission system planning criteria switchyard voltage range is 98% to 105% of the nominal 345 kV (i.e., 338.1 kV to 362.3 kV). The expected minimum voltage is based on expected system loading with both units offline at two unit sites with the included impact of the loss of reactive power support. Dual unit sites are analyzed with the loss of the unit assuming accident loading concurrent with the worst-case additional contingency.

Additionally, PJM has set emergency transmission system voltage criteria to respond to extreme grid conditions that may result in voltage on the 345 kV system dropping below 98% of nominal. These criteria state that every effort, including reduction of system load, will be made to maintain the 345 kV transmission system voltage above 95% of nominal.

As demonstrated above, the minimum expected voltage in SPOG 2-1 for the 345 kV system (i.e., approximately 103% of nominal) met the QCNPS requirements for operability of offsite power. However, following the transfer to PJM, the minimum transmission planning criteria voltage (i.e., 98% of nominal) and the emergency criteria (i.e., 95% of nominal) do not meet the QCNPS requirements for operability. Since the spring of 2004, the state estimator has generated frequent alarms for QCNPS Units 1 and 2, indicating that the predicted post-trip voltage was below the minimum required to ensure the operability of the offsite power sources. In each case, QCNPS and EED took compensatory actions such as reducing QCNPS auxiliary loads and/or increasing voltage support from other units to restore the operability of the offsite circuits.

In response to this frequent condition, QCNPS initiated actions to procure a replacement for TR 12 and TR 22 and to seek approval for use of the LTCs in automatic mode. The LTCs will regulate the voltage supplied to the ESS buses to compensate for variations in the transmission system voltage. The use of LTCs in automatic operation will allow the operability of the offsite power circuits at QCNPS to be maintained over the range of voltage specified in the transmission planning criteria and emergency criteria (i.e. 95% to 105% of nominal).

4.0 TECHNICAL ANALYSIS

Description of Transformer and LTC Modifications

The modification to upgrade the Unit 1 and 2 RATs with the LTC in manual operation has been evaluated in accordance with 10 CFR 50.59 and determined to not require NRC approval prior to implementation. The replacement RATs will be a 62.5 MVA 345/4.3 kV transformer with a LTC. The LTC will regulate the output voltage of the RAT to the respective 4160 V ESS buses.

The tap changer mechanism for the LTC is located in a separate enclosure attached to the transformer. A drive motor rotates the tap changer to increase or decrease the number of transformer windings in service. The LTC has two modes of operation, automatic and manual. When operating in its automatic mode, the LTC controller raises and lowers voltage by operating the drive motor. The controller monitors load and source voltage to create an "error" signal based on sensed secondary voltage, which changes the tap setting when required so that voltage is controlled to within the desired range. The tap changer controller uses a primary and a backup controller with a self-testing watchdog system to select the properly functioning controller. A light emitting diode indicator on the controller serves as a display to verify "CPU OK" status, indicated locally at the control panel on the transformer. The tap changer can also be operated in a manual control mode, which also uses the drive motor to rotate the tap changer.

The LTC will provide a range of -5% to +25% of the rated secondary voltage in 32 steps, each step being 0.938 %. The LTC has sufficient range to respond to the expected 345 kV system range of 95% to 105% of nominal. By providing automatic adjustment of the voltage to the QCNPS auxiliary power system from the offsite 345 kV system, the TR 12 and TR 22 LTCs will compensate for a wide range of 345 kV system operating voltages in the future.

The regulating relays controlling the LTCs are set with an initial delay of 1 second. The voltage must be out of band for 1 second before the controls initiate a tap change. Once given a signal to change taps, either manually or automatically, the tap changer will complete a tap change in two seconds.

In the event of a voltage dip with no accident signal present, the second-level degraded voltage relay scheme includes a nominal 5-minute timer to allow voltage to recover before the safety buses are disconnected from offsite power. The 5-minute timer allows adequate time to complete needed tap changes to correct the transient before disconnecting from offsite power.

In the event of a voltage dip concurrent with an accident, the second-level degraded voltage relays are set with a nominal time delay of 7 seconds before which, if the voltage does not recover, the safety buses will be disconnected from offsite power. If a loss-of-coolant accident were to occur at full power operations and the switchyard voltage were to dip to the minimum value, it has been determined that two tap changes are required to support the additional continuous load imposed on the transformer. Considering the additional time needed for the 1-second initial delay before the two tap changes begin, the LTC will complete voltage correction in 5 seconds. The allowable value for the nominal 7-second degraded voltage time delay is > 5.7 seconds and < 8.3 seconds, as specified in the Technical Specifications Table 3.3.8.1-1, "Loss of Power Instrumentation." Therefore, the LTC will be successful in preventing a trip of

the degraded voltage relays in the event of a voltage dip, precluding unnecessary disconnection of the safety buses from offsite power.

Following installation, each transformer will be subject to standard transformer tests during its acceptance testing. These tests include Doble/sweep frequency response, transformer through-fault, core ground, turns ratio on all taps, low voltage excitation, winding megger, and alternate current impedance testing. Also, operation of the LTC over the full range of tap position will be verified. Testing performed on the main and backup controllers will include verifying with a simulated voltage input that the LTC regulating relay provides the correct raise/lower response and the LTC backup relay provides the proper blocking function.

LTC Automatic Operation Failure Modes Evaluation

EGC has evaluated the potential failure modes of the LTC and its control system, and the results of that evaluation are discussed below and summarized in Table 1. Use of the LTC in automatic mode creates the possibility for a malfunction of the LTC controller that raises or lowers the voltage provided to the ESS buses. Since all of the required plant safety buses could be aligned to the unit RAT (e.g., during offline conditions) such a malfunction could affect safety systems or equipment in multiple divisions. The condition created when the LTC controller automatically lowers the voltage provided to the ESS buses was previously evaluated and is addressed by the LOP instrumentation. However, the condition created when the LTC controller automatically raises the voltage provided to the ESS buses has not been previously evaluated in the QCNPS UFSAR. As a result, in accordance with 10 CFR 50.59, the use of the LTC in automatic mode requires NRC approval, since the potential malfunction of the LTC creates a possibility for a malfunction of a structure, system, or component important to safety with a different result than any previously evaluated in the UFSAR. However, as discussed in the following paragraphs, this potential malfunction is unlikely, and operator action can be taken to prevent a sustained high voltage condition. Furthermore, as discussed in Section 5.1 below, the potential malfunction does not significantly increase the probability or consequences of an accident previously evaluated, does not create the possibility of a new or different kind of accident, and does not involve a significant reduction in a margin of safety.

The most severe potential malfunction would be a failure of the primary controller that causes transformer output voltage to rapidly increase or decrease. The backup controller prevents a defective LTC tap changer control from running the voltage outside established upper and lower limits by blocking the raise and lower logic of the tap changer. The backup control will also lower the voltage (i.e., lower the tap position) if the regulated voltage remains above the upper voltage limit for a set period of time. The design also allows the operators to override both LTC controllers, taking manual control if necessary.

EGC has obtained current data on the predicted mean time between failure rates of the controllers from the manufacturer. For the primary controller, the predicted mean time between failures is 145 years and for the backup controller, the predicted mean time between failures is 542 years. Both calculations are based on figures current as of September 30, 2004. Thus, the failure of both controllers simultaneously is unlikely. QCNPS controller maintenance and testing activities will provide reasonable assurance that these mean time failure rates are maintained.

In the unlikely event of a failure of both the primary and backup controllers that results in rapidly increasing voltage, operators can take manual action from the RAT control cabinets to prevent

damage to safety related equipment. The 4160 V ESS buses are equipped with a process computer alarm that indicates an over-voltage condition has occurred. The control room computer alarm setpoint is established at 4300 V, which is conservatively below the 110% voltage rating of the safety related motors fed from the bus, consistent with ANSI/NEMA Standard MG-1-2003, "Motors and Generators."

Damage from an over-voltage condition is only expected if the condition is sustained. At voltages below 4400 V, there is no possibility of causing an over-voltage on 4000 V motors, since this is within the 110% NEMA criteria. At voltages below 4300 V on the ESS bus, there is minimal possibility of creating an over-voltage on a 460 V motor that is fed from a 480 V bus tied to the ESS bus. As load on the 480 V system increases, the actual voltage on the high side (4160 V) of the unit substation transformer will decrease due to the impedance of the transformer.

Operators will be directed to respond under the guidance of abnormal operating procedures upon receipt of a 4160 V ESS bus over-voltage alarm. The procedural guidance will direct operators to take manual control of the LTC. The tap setting can then be manually lowered to correct bus voltage. Additionally, plant conditions permitting, the running of safety related loads can be avoided in order to minimize degradation of the equipment. Also, as conditions permit, non-safety related loads are added to help lower bus voltage.

As such, the existing over-voltage alarm, in conjunction with the procedurally controlled operator actions to promptly correct the condition, is considered sufficient protection against a primary and backup controller failure that results in rapidly increasing voltage and limits the duration of any over-voltage condition.

A failure that results in rapidly decreasing voltage could initiate the five-minute timer on the 4160 V ESS bus degraded voltage relays if voltage were to decrease to the current TS setpoint (3948 V-3885 V). Failure to restore the bus voltage within approximately five minutes would cause the power source for these buses to transfer to the emergency diesel generators. A loss of offsite power is analyzed in the UFSAR. Again, the presence of the backup controller makes this failure extremely unlikely, and a low voltage alarm at approximately 3900 V alerts operators to take procedurally-guided action prior to reaching the degraded voltage relay setpoint.

Other LTC failure modes or malfunctions that could lead to an over-voltage or under-voltage condition or result in the tap changer failing to change the tap setting when expected (i.e., the tap setting remains "as is") are identified in Table 1. This can result from a failure of the controller when the LTC is operating in the automatic mode, or from a failure of the drive motor within the LTC (including a loss of power to the drive motor) when the LTC is operating in either the automatic or manual mode. In either case, an over-voltage or under-voltage condition could be created if transmission system voltage changed subsequent to the failure. For example, if the failure occurred during the afternoon of a day when high summer load demand existed, a high tap setting could lead to a high voltage condition later that evening when system load demand diminishes and grid voltage increases.

Failures of the tap changer to change settings when demanded are less severe than active failures of the LTC, since the over-voltage or under-voltage condition would evolve relatively slowly and the magnitude of the resultant change in voltage would be limited to the effect of the change in grid voltage. As noted previously, there are alarms that alert the operator to high

voltage conditions on the 4160 V ESS buses, and procedures will be established to instruct the operators to take action to mitigate or correct the condition. The first action is to contact the transmission system operator and request that the voltage be increased or decreased as needed. Further actions include either securing/preventing the start of loads, or adding additional load based on the scenario. The operator can also arrange for manual operation of the tap changer to change the tap setting if required.

Similar LTC transformers are in use at other NRC-licensed facilities. An operating experience (OPEX) review that focused on load tap changer issues at nuclear power plants was performed. Only two instances of an LTC controller spuriously running voltage to an extreme value were identified. Isolated instances of the tap changer failing as-is were reported. There were no documented instances of equipment failures resulting from LTC failure. Given the number of licensed units employing transformers with load tap changers and the period of time in operation, it is reasonable to conclude the few issues identified in the OPEX search do not constitute an equipment reliability issue.

Evaluation of Offsite Circuit Operability with Non-Functional LTCs

Implementation of automatic operation of the LTCs will compensate for variations in switchyard voltage that could otherwise render the offsite circuits inoperable. In the event the LTC is non-functional and unable to compensate for switchyard voltage variations, offsite circuit operability will be determined based on whether the actual and predicted post-trip voltage at the switchyard is adequate to prevent the LOP instrumentation from transferring the ESS bus source to the DGs.

Conclusion

Implementation of automatic LTC operation will ensure that the voltage provided by the transmission system is adequate to maintain operability of the offsite power sources for QCNPS, Units 1 and 2 for the expected range of switchyard voltages. LTCs have proven to be reliable, and the likelihood and consequences of each of the failure modes of the LTCs has been evaluated and determined to be acceptable. Thus, the proposed changes will increase overall reliability of the offsite power sources at QCNPS, Units 1 and 2.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

According to 10 CFR 50.92, "Issuance of amendment," paragraph (c), a proposed amendment to an operating license involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not:

(1) Involve a significant increase in the probability or consequences of an accident previously evaluated; or

(2) Create the possibility of a new or different kind of accident from any accident previously evaluated; or

(3) Involve a significant reduction in a margin of safety.

EGC has evaluated the proposed changes for QCNPS, Units 1 and 2 using the criteria in 10 CFR 50.92, and has determined that the proposed changes do not involve a significant hazards consideration. The following information is provided to support a finding of no significant hazards consideration.

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

   Response: No

   The requested change allows the automatic operation mode of the LTC. The only accident previously evaluated for which the probability is potentially affected by the change is the loss of offsite power (LOOP). A failure of the LTC while in automatic operation mode that results in decreased voltage to the ESS buses could cause a LOOP. This could occur in two ways. A failure of the LTC controller that results in rapidly decreasing the voltage to the emergency buses is the most severe failure mode. However, a backup controller is provided with the LTC that makes this failure unlikely. A failure of the LTC controller to respond to decreasing grid voltage is less severe, since grid voltage changes occur slowly. In both of the above potential failure modes, operators will take manual control of the LTC to mitigate the effects of the failure. Thus, the probability of a LOOP is not significantly increased.

   The proposed change has no effect on the consequences of a LOOP, since the emergency diesel generators provide power to safety related equipment following a LOOP. The emergency diesel generators are not affected by the proposed change.

   The probability of other accidents previously evaluated is not affected, since the proposed change does not affect the way plant equipment is operated and thus does not contribute to the initiation of any of the previously evaluated accidents.

   The LTC is equipped with a backup controller, which controls the LTC in the event of primary controller failure. Additionally, operator action is available to prevent a sustained high voltage condition from occurring. Damage due to over-voltage is time-dependent. Therefore, damage to safety related equipment is extremely unlikely, and the consequences of these accidents are not significantly increased. The only way in which the consequences of other previously evaluated accidents could be affected is if a failure of the LTC, while in automatic operation mode, led to a sustained high voltage condition, which resulted in damage to safety related equipment that is used to mitigate an accident.

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

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

Response: No

The proposed change involves functions that provide offsite power to safety related equipment for accident mitigation. Thus, the proposed change potentially affects the consequences of previously evaluated accidents (as addressed in Question 1), but does not result in any new mechanisms that could initiate damage to the reactor and its principal safety barriers (i.e., fuel cladding, reactor coolant system, or primary containment).

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

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

Response: No

The proposed change does not affect the inputs or assumptions of any of the analyses that demonstrate the integrity of the fuel cladding, reactor coolant system, or containment during accident conditions. The allowable values for the degraded voltage protection function are unchanged and will continue to ensure that the degraded voltage protection function actuates when required, but does not actuate prematurely to cause a LOOP. Automatic operation of the LTC increases margin by reducing the potential for transferring to the EDGs during an event.

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

Based on the above, EGC concludes that the proposed UFSAR change presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of no significant hazards consideration is justified.

5.2 Applicable Regulatory Requirements/Criteria

10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants," Criterion 17, "Electric power systems," requires, in part, that offsite power be available to the facility to ensure that specified fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded. Criterion 17 further requires that 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 unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.

To satisfy Criterion 17 of the General Design Criteria (GDC), adequate voltage must be maintained in order to ensure that the offsite power source remains available to provide power to safety related equipment. Providing adequate voltage ensures that degraded voltage relays, which protect the auxiliary power system from operating at low voltages that could damage

equipment, would not actuate to separate the safety related buses from the offsite power sources as a result of the loss of output from the generating unit.

10 CFR 50.59 allows licensees to make changes to the plant as described in the UFSAR only if the changes do not result in a malfunction of a structure, system, or component important to safety with a different result than any previously evaluated in the UFSAR. As discussed in Section 4.0 above, the use of LTCs in automatic operation creates the possibility for a malfunction of a structure, system, or component important to safety with a different result than any previously evaluated in the UFSAR.

As demonstrated in Section 4.0 above, usage of the LTC automatic operation mode for TR 12 and TR 22 will ensure that the offsite power capabilities of QCNPS remain in compliance with the requirements of GDC 17 and ensure that the offsite power sources remain operable under all expected voltage variations in accordance with Technical Specification requirements.

6.0 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, "Standards for Protection Against Radiation," 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 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, "Criterion for categorical exclusion; identification of licensing and regulatory actions eligible for categorical exclusion or otherwise not requiring environmental review," Paragraph (c)(9). Therefore, pursuant to 10 CFR 51.22, Paragraph (b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

7.0 PRECEDENT

Regarding automatic operation of the LTCs, the NRC has granted similar license amendments for the Clinton Power Station and the Callaway Plant, in References 1 and 2, respectively.

8.0 REFERENCES

1. Letter from U. S. NRC to J. V. Sipek (Illinois Power Company), "Issuance of Amendment No. 116 to Facility Operating License No. NPF-62 – Clinton Power Station, Unit 1," dated October 1, 1998

2. Letter from U. S. NRC to G. L. Randolph (Union Electric Company), "Callaway Plant, Unit 1 – Issuance of Amendment regarding Installation of replacement Engineered Safety Features Transformers," dated April 6, 2001

TABLE 1

LTC Automatic Operation Potential Failure Mode	Impact	Response
LTC controller attempts to raise tap setting when not needed.	Could cause over-voltage condition	Backup controller maintains acceptable tap position. Additionally, alarm on over-voltage will initiate operator action to place LTC in manual mode.
LTC controller attempts to lower tap setting when not needed.	Could cause under-voltage condition	Backup controller maintains acceptable tap position. Additionally, alarm on low voltage will initiate operator action to place LTC in manual mode. In extreme case, results in a loss of offsite power, which has been evaluated as part of plant design basis.
LTC controller malfunctions to keep tap setting as-is.	Could cause over-voltage (or under-voltage) if grid voltage changes following failure	Operator action to monitor voltage and respond by placing LTC in manual mode and raising or lowering voltage as desired.
LTC drive motor fails (or power to motor is lost) causing tap setting to remain as-is.	Could cause over-voltage (or under-voltage) if grid voltage changes following failure	Operator action to monitor voltage and raise or lower voltage as desired by the transmission operator and/or adjusting on-site loads.

ATTACHMENT 2
Marked-up UFSAR Page with Proposed Change

Page

8.3-5

A 3-hour rated, seismic Class I fire barrier is installed between the 4160-V switchgear 13-1 and 14-1 to prevent fire from spreading from one switchgear area to the other for Unit 1. A similar barrier is also installed between switchgear 23-1 and 24-1 for Unit 2. [8.3-14]

8.3.1.2.2 Systems Components

The major components of the 4160-V system are the UAT, the RAT, the 4160-V switchgear, and the circuit breakers. The UAT is described in Section 8.3.1.1.2.4. [8.3-15]

8.3.1.2.2.1. Reserve Auxiliary Transformer

The RAT (TR-12 for Unit 1 and TR-22 for Unit 2) steps switchyard voltage from 345 kV down to 4160 V for use with station auxiliary loads. The rating of the transformer is given in Table 8.3-1.

Insert #1

8.3.1.2.2.2 4160-V Switchgear

The 4160-V switchgear provides a means of enclosing the bus work, breakers, and relays associated with the 4160-V system. The switchgear for the 4160-V buses is located in the turbine building and the Station Blackout Building. [8.3-16]

8.3.1.2.2.3 Circuit Breakers

Circuit breakers provide a method of isolating loads and power supplies from the 4160-V buses. The breakers are supplied in three current ratings: 1200A, 2000A, and 3000A.

8.3.1.3 13.8-kV System

Power to non-plant facilities is supplied by transformers TR-81 and TR-82. These are 345-kV to 13.8-kV transformers connected to the 345-kV ring bus. The 13.8-kV distribution system consists of bus work, disconnects, breakers, and transformers necessary to supply non-plant facility loads, including normal power to the SBO DG building. [8.3-17]

8.3.1.4 480-V System

Power is supplied from 4160-V buses 13, 14, 13-1, and 14-1 to the 480-V buses through nine separate transformers including the well water pumphouse and gatehouse transformers. The 480-V buses supply power to electrically operated auxiliaries. The 480-V buses are the indoor load center type which in addition to supplying power directly to the 480-V motor loads also supply the transformers used in stepping down the voltage to 208/120 V for lighting, instrumentation, and small plant service loads. The power for

Insert 1

TR 12 and TR 22 are 345-4.3-4.3 kV three winding transformers with an automatic load tap changer (LTC) on the 4.3 kV X-winding. The LTCs provide a range of +25% to –5% of the rated voltage in 32 steps, each step being approximately 0.938% of rated voltage. The LTC may be operated manually or in the automatic (voltage regulating) mode.

The automatic LTC has both a primary and backup controller. The backup controller prevents the primary unit from running the secondary side voltage outside of the desired upper and lower limits in the event of a primary controller failure.

Automatic operation of the LTC was evaluated in license amendment number xxx/yyy approved by the NRC. The evaluation determined that the potential failure modes of the LTC are not likely to cause a common mode failure of the safety related equipment powered from TR 12 or TR 22. A failure in which the LTC rapidly increases or decreases transformer output voltage is not likely, since both the primary and backup controllers would have to fail. A failure of the LTC to respond to changing transmission system voltage would occur slowly and can be mitigated by operator action.