March 17, 2006

Mr. Christopher M. Crane, President
and Chief Nuclear Officer
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3 - ISSUANCE OF AMENDMENTS REGARDING OFFSITE POWER INSTRUMENTATION AND VOLTAGE CONTROL (TAC NOS. MC6712 AND MC6713)

Dear Mr. Crane:

The Commission has issued the enclosed Amendment No. 219 to Renewed Facility Operating License No. DPR-19 and Amendment No. 210 to Renewed Facility Operating License No. DPR-25 for Dresden Nuclear Power Station, Units 2 and 3 (DNPS). The amendments are in response to your application dated April 4, 2005, as supplemented by letter dated January 13, 2006, that requested revisions to the DNPS Technical Specifications (TSs) and the Updated Final Safety Analysis Report (UFSAR).

The amendments revise TS Section 3.3.8.1, “Loss of Power (LOP) Instrumentation,” and also revise the UFSAR to implement use of automatic load tap changers on transformers that provide offsite power to DNPS.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Maitri Banerjee, Senior Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-237 and 50-249

Enclosures:
1. Amendment No. 219 to DPR-19
2. Amendment No. 210 to DPR-25
3. Safety Evaluation

cc w/encls: See next page

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TS Pages: ML

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EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-237

DRESDEN NUCLEAR POWER STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 219
License No. DPR-19

1. The Nuclear Regulatory Commission (Commission) has found that:

    A. The application for amendment by the Exelon Generation Company, LLC (the licensee) dated April 4, 2005, as supplemented by letter dated January 13, 2006, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

    B. The facility will operate in conformity with the application, the provisions of the Act and the rules and regulations of the Commission;

    C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

    D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

    E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended to authorize revision of the Updated Final Safety Analysis Report (UFSAR) as set forth in the application for amendment by the licensee, dated April 4, 2005, as supplemented by letter dated January 13, 2006. The licensee shall update the UFSAR to revise the description of the offsite source to include the automatic load tap changer operation, as authorized by this amendment and in accordance with 10 CFR 50.71(e). Additionally, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Renewed Facility Operating License No. DPR-19 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 219, are hereby incorporated into this renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA by L.Raghavan for/

Mindy S. Landau, Acting Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: March 17, 2006

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-249

DRESDEN NUCLEAR POWER STATION, UNIT 3

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No.210
License No. DPR-25

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by the Exelon Generation Company, LLC (the licensee) dated April 4, 2005, as supplemented by letter dated January 13, 2006, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended to authorize revision of the Updated Final Safety Analysis Report (UFSAR) as set forth in the application for amendment by the licensee, dated April 4, 2005, as supplemented by letter dated January 13, 2006. The licensee shall update the UFSAR to revise the description of the offsite source to include the automatic load tap changer operation, as authorized by this amendment and in accordance with 10 CFR 50.71(e). Additionally, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 3.B. of Renewed Facility Operating License No. DPR-25 is hereby amended to read as follows:

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 210, are hereby incorporated into this renewed operating license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 60 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA by L.Raghavan for/

Mindy S. Landau, Acting Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: March 17, 2006

ATTACHMENT TO LICENSE AMENDMENT NOS. 219 AND 210

RENEWED FACILITY OPERATING LICENSE NOS. DPR-19 AND DPR-25

DOCKET NOS. 50-237 AND 50-249

Replace the following page of the Appendix “A” Technical Specifications with the attached page. The revised page is identified by amendment number and contains marginal lines indicating the area of change.

Remove	Insert
3.3.8.1-3	3.3.8.1-3

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION RELATED

TO AMENDMENT NO. 219 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-19

AND AMENDMENT NO. 210 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-25

EXELON GENERATION COMPANY, LLC

DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3

DOCKET NOS. 50-237 AND 50-249

1.0 INTRODUCTION

By letter to the Nuclear Regulatory Commission (NRC, Commission) dated April 4, 2005 (Agencywide Documents Access and Mangement System (ADAMS) Accession Number ML050950222), as supplemented by letter dated January 13, 2006, (ADAMS Accession Number ML060170218), Exelon Generation Company, LLC (the licensee) requested changes to Appendix A, Technical Specifications (TSs), of the Renewed Facility Operating Licenses for the Dresden Nuclear Power Station (DNPS), Units 2 and 3. The proposed changes would revise TS Section 3.3.8.1, "Loss of Power (LOP) Instrumentation," and would also revise the Updated Final Safety Analysis Report (UFSAR) to implement the use of automatic load tap changers (LTCs) on transformers that provide offsite power to DNPS, Units 2 and 3.

The proposed change to TS 3.3.8.1 would revise the maximum and minimum allowable values (AVs) for the degraded voltage function of the 4160 volt (V) essential service system (ESS) bus undervoltage instrumentation. The licensee stated that this proposed change provides additional operating flexibility to prevent unnecessary actuation of degraded voltage protection relays while maintaining adequate degraded voltage protection for safety-related equipment.

The licensee stated that LTCs are subcomponents of new transformers that have been or are being installed to compensate for potential offsite power voltage fluctuation in order to continue to ensure that acceptable voltage is maintained for safety-related equipment. While the DNPS, Unit 2 transformer is already equipped with an LTC, the licensee stated that the LTC for Unit 3 was an integral part of the new transformer scheduled for installation within the next 24 months. The licensee requested the NRC staff's approval to operate the LTCs in automatic mode. Both LTCs will be operated only in manual mode (which does not require prior NRC staff approval in accordance with 10 CFR 50.59, "Changes, tests, and experiments") until the requested changes 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 source will be revised to describe the automatic LTC operation. Operation of the LTCs in automatic mode requires the NRC staff's approval in accordance with 10 CFR 50.59, since automatic LTC operation could create the possibility of a previously unevaluated malfunction of a structure, system, or component (SSC) important to safety. The proposed change thus involves an unreviewed safety question.

The supplement dated January 13, 2006, provided additional information that clarified the application, did not expand the scope of the application as initially noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on November 8, 2005 (70 FR 67747).

2.0 BACKGROUND

At DNPS, Units 2 and 3, power to safety-related equipment is provided by two divisions of 4160 V ESS buses. For each unit, one division of the ESS buses 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 reserve auxiliary transformer (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. The LOP instrumentation monitors the ESS buses. 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.

Prior to October 2003, the DNPS, Unit 2 ESS buses received offsite power from the 138 kV transmission system connected through RAT 22. In October 2003, due to possible future voltage concerns on the 138 kV transmission system, the licensee transferred the source of RAT 22 from the 138 kV transmission system to the 345 kV transmission system. The connection from the 345 kV transmission system to RAT 22 was accomplished with a new 345/138 kV transformer, TR 86. To provide voltage regulation capacity, TR 86 was equipped with an LTC.

The DNPS, Unit 3, ESS buses receive offsite power from the 345 kV transmission system connected through RAT 32, which was not equipped with an LTC at the time of the licensee's application for the subject license amendment. Exelon Energy Delivery (EED) is the transmission system operator for DNPS. The EED transmission system is part of the Pennsylvania, New Jersey, Maryland (PJM) interconnect network. For transmission planning purposes, EED maintains transmission system planning criteria for setting the maximum voltage and the expected minimum voltage for the transmission system. The transmission system planning criteria switchyard voltage range is 98 percent to 105 percent of the nominal 345 kV, or 338.1 kV to 362.3 kV. The expected minimum voltage is based on expected system loading with both units off line at dual-unit sites and includes the impact of the loads of reactive power support. Single-unit sites (or dual-unit sites such as DNPS that have normally open bus tie breakers on a double-ring bus) are analyzed with the loss of the unit, assuming accident loading concurrent with the worst-case additional contingency.

In addition to transmission system planning criteria, EED had previously maintained a System Planning Operating Guide (SPOG) 2-1 that provided expected actual switchyard voltages at the nuclear stations, based on studies of projected load growth. The most recent version of SPOG 2-1 stated that the expected voltage (with the same operational contingencies used for planning purposes) would be maintained between 101 percent and 105 percent of the nominal voltage on the 345 kV system, or 348 kV to 362.3 kV through June 1, 2004. The transmission system planning criteria described above were implemented after June 1, 2004, with the transition to the PJM network. The PJM network has also set emergency transmission system voltage criteria to respond to extreme grid conditions that may cause the voltage on the 345 kV

system to drop below 98 percent 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 percent of nominal.

The licensee states that to maintain operability of the offsite power circuits, the minimum required switchyard voltage is approximately 345 kV for DNPS Unit 2 and approximately 344 kV for DNPS Unit 3. These voltages ensure that the voltage is adequate at the ESS buses under accident loading conditions. The minimum expected voltage in SPOG 2-1 for the 345 kV system (i.e., 101 percent of nominal) met the DNPS requirements for operability of offsite power. However, the minimum transmission planning criteria voltage (i.e., 98 percent of nominal) and the minimum emergency criteria voltage (i.e., 95 percent of nominal) do not meet the DNPS requirements for operability. Prior to the transition to the PJM network, the expected minimum switchyard voltage in SPOG 2-1 did not bound every possible combination of transmission system contingencies. Due to unforseen changes in generation and load patterns, the actual minimum voltage may be lower than the expected voltage. A state estimator was used with contingency analysis applications to monitor real-time grid conditions and determined the predicted switchyard voltage following a trip of one of the DNPS units. In the spring of 2004, the state estimator generated alarms on several days for DNPS Unit 3, indicating that the predicted post-trip voltage was below the minimum required to ensure operability of the offsite power source. In each case, DNPS and EED took compensatory actions such as reducing DNPS Unit 3 auxiliary loads, connecting system capacitors, and/or increasing voltage support from other units to restore the operability of the offsite circuits. In response to these conditions, the licensee initiated actions to procure a replacement for TR 32 that is equipped with an LTC and to seek the NRC staff's approval to use the LTCs on TR 86 and TR 32 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 DNPS to be maintained over the range of voltage specified in the transmission planning criteria and emergency criteria (i.e., 95 percent to 105 percent of nominal).

TR 86, which was installed in October 2003, is a 100 megavolt-ampere (MVA) 345/138 kV transformer with an LTC. The LTC will regulate voltages to the plant RAT 22 transformer. The RAT 32 installed at the time of the license amendment application was a 51.5 MVA 345/4.16 kV transformer. The replacement for RAT 32 is a 62.5 MVA 345/4.24 kV transformer with an LTC. The LTC will regulate the output voltage of RAT to the 4160 V ESS buses.

3.0 REGULATORY EVALUATION

The NRC staff finds that the licensee, in Section 4.0 of its submittal, identified the applicable regulatory requirements. The regulatory requirements for which the NRC staff based its acceptance are described below.

General Design Criterion (GDC) 17, "Electric power systems," of Title 10 to the *Code of Federal Regulations* (10 CFR), Part 50, Appendix A, requires that nuclear power plants have onsite and offsite electric power systems to permit the functioning of SSCs that are important safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system must be supplied by two physically independent circuits that are 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. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of LOP from the unit, the offsite transmission network, or the onsite power supplies.

GDC 18, "Inspection and testing of electric power systems," requires that electric power systems that are important to safety be designed to permit appropriate periodic inspection and testing.

Section 50.36, "Technical Specifications," of 10 CFR requires that limiting conditions for operation be established for SSCs that are part of the primary success path and which function to mitigate a design-basis accident.

Section 50.59 of 10 CFR allows licensees to make changes to the plant as described in the UFSAR if certain criteria are met, including if the changes do not result in a different malfunction of a SSC important to safety than previously evaluated in the UFSAR. The licensee concluded that the proposed change created the possibility for a malfunction of a SSC important to safety with a different result than any previously evaluated in the UFSAR.

4.0 TECHNICAL EVALUATION

The NRC staff has reviewed the licensee's regulatory and technical analyses in support of its proposed license amendment which are described in Sections 4.0 and 5.0 of the licensee's submittal. The detailed evaluation below will support the conclusion that: (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.

4.1 Revision to TS 3.3.8.1, 4160 V Service System Bus Undervotage (Degraded Voltage)

TS Table 3.3.8.1-1, Loss of Power Instrumentation, Function 2.a, Bus Undervoltage/Time Delay, requires that the maximum and minimum AVs for the function be 3911 V and 3861 V, respectively. The proposed change would revise the maximum and minimum AVs to 3881 V and 3851 V, respectively.

The LOP instrumentation monitors the 4160 V ESS bus to ensure that adequate voltage is available for the components required to mitigate accidents. During normal operation, when a degraded voltage function setpoint has been exceeded and persists for 7 seconds on both relay channels, a control room annunciator alerts the operators of the degraded voltage condition and the 5-minute time delay function timer is initiated. If the degraded voltage condition does not clear within 5 minutes, the 5-minute time delay function relay sends an LOP signal to the respective bus load shedding scheme and starts the associated DG. Alternatively, if a degraded voltage condition exists coincident with an emergency core cooling system actuation signal, the 5-minute time delay function is bypassed so that load shedding and the associated DG start will be initiated following the 7-second inherent time delay. Since the LOP instrumentation affects the availability of adequate power supply for certain ECCS functions and

is required for the transfer function (from the offsite power supply to the emergency DG) only, the LOP instrumentation is not a limiting safety system setting (LSSS) needed to protect a safety limit.

The analytical limit is for the minimum voltage of 3820 V (91.8 percent of 4160 V) at which all safety-related equipment fed from the ESS buses has adequate terminal voltage to start and run. Based on this analytical limit, setpoint calculations are performed to establish the AVs and corresponding relay setpoints and tolerances (setting tolerance, expanded tolerance).

The degraded voltage setpoint calculations have been revised to reduce the total uncertainty while maintaining the existing analytical limit for the minimum voltage value. This change was accomplished by reclassifying the potential transformer (PT) uncertainty term from nonrandom to random in accordance with the setpoint methodology. The PT is a separate device which provides the actual ESS bus voltage to the undervoltage relay. Therefore, the uncertainty of the PT is considered an independent random term in calculating total channel uncertainty. Based on this change in the PT's uncertainty term, revised AVs were determined in accordance with the setpoint methodology described in the licensee's engineering standard NES-EIC-20.04, "Analysis of Instrument Channel Setpoint Error and Instrument Loop Accuracy, which was accepted by NRC for DNPS on March 30, 2001 (Reference 1). The setpoint calculation utilizes the setpoint methodology to calculate the dropout voltage setpoint by using the revised value of the total negative uncertainty in determining the minimum setpoint and AVs, and the revised value of the total positive uncertainty in determining the maximum setpoint and AVs. Based on its review of the licensee's results of the uncertainty analyses and the setpoint calculation, the NRC staff found that the maximum AV of 3881 V and the minimum AV of 3851 V are conservative and concluded that the revised maximum and minimum allowable values are acceptable. The NRC staff has also evaluated the licensee's setpoint methodology and calibration procedures (MA-DR-771-402 and MA-DR-771-403) and found that the licensee's setpoint methodology and calibration procedures demonstrate that the voltage setpoint and setting tolerance specified in the licensee's calibration procedures are established and held within specified limits to protect the analytical limit (minimum operating voltage) for the ESS equipment. Therefore, the revised allowable voltage values are acceptable.

4.2 Load Tap Changer

The tap changer mechanism for the LTCs for both transformers is located in a separate enclosure attached to the transformers. The LTC has two modes of operation, automatic and manual. A drive motor rotates the tap changer to increase or decrease the number of transformer windings in service. 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 on the control panel on the

transformer. The tap changer can also be operated in a manual control mode using the drive motor to rotate the tap changer.

For TR 86, the LTC will provide a range of plus or minus 10 percent of the rated voltage in 33 steps, each step being 0.625 percent. TR 86 also contains a fixed ratio, deenergized tap changer (DETC) on the primary windings. The combination of the DETC and the LTC determines the overall range of the TR 86 output. The secondary voltage of TR 86 can be varied to achieve plus or minus 15 percent of nominal. The LTC has sufficient range to respond to the expected 345 kV system range of 95 percent to 105 percent of nominal.

For TR 32, the LTC will provide a range of plus 25 percent to minus 5 percent of the rated voltage in 33 steps, each step being 0.9375 percent. Thus, the tap changer is expected to be able to compensate for the expected switchyard voltage range of 95 percent to 105 percent of nominal voltage. The licensee stated that the response time of the TR 32 LTC is the same as the response time of the TR 86 LTC. TR 32 does not have a DETC. By adjusting the voltage provided to the DNPS auxiliary power system from the offsite 345 kV system, the TR 86 and TR 32 LTCs will compensate for a wider range of 345 kV system operating voltages in the future.

The licensee has evaluated the potential failure modes of the LTC and its control system. 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 will prevent a defective LTC control from running the voltage outside the 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 operator to override both LTC controllers, taking manual control if necessary. The licensee has stated that it has obtained current data from the manufacturer on the predicted mean time between failure rates of the controllers. 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 data are based on figures current as of September 30, 2004. Thus, the licensee evaluated that simultaneous failure of both controllers is unlikely.

In the unlikely event that a failure of both the primary and backup controllers results in rapidly increasing voltage, operators can take manual action from the control room to prevent damage to safety-related equipment. The 4160 V ESS buses are equipped with a process computer alarm that indicates an overvoltage condition has occurred. The computer alarm setpoint is established at 4300 V, which is conservatively below the 110 percent 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 overvoltage condition is only expected if the condition is sustained. At a voltage below 4300 V, there is no possibility of causing an overvoltage on 4000 V motors, since a voltage below 4300 V is within the 110 percent NEMA criterion. At voltage below 4300 V on the ESS bus, there is minimal possibility of creating an overvoltage 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 respond by following the guidance of established abnormal operating procedures upon receipt of the

4160 V ESS bus overvoltage alarm. The procedural guidance directs the operator to take manual control over the LTC. The tap setting can be manually lowered from the control room to correct bus voltage. Thus, the existing overvoltage alarm, in conjunction with the procedurally controlled operator actions to promptly correct the condition will limit the duration of any overvoltage condition in the unlikely event of a primary and backup controller failure that results in rapidly increasing voltage.

An LTC failure that results in rapidly decreasing voltage could initiate the 5-minute timer on the 4160 V ESS bus degraded voltage relays if the voltage decreased to the current setpoint of 3874 V. Failure to restore the bus voltage within 5 minutes would cause the power source for these buses to transfer to the emergency DGs. A loss of offsite power is analyzed in the UFSAR. The licensee stated that the presence of the backup controller makes this failure extremely unlikely, and a low-voltage alarm at 4000 V warns 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 overvoltage or undervoltage condition or cause the tap changer to fail to change the tap setting when expected (i.e., the tap setting remains “as is”) were identified. These malfunctions can result from a failure of the drive motor (including a LOP to the drive motor) when the LTC is operating in either the automatic or the manual mode. In either case, an overvoltage (or undervoltage) condition could be created if transmission system voltage changed subsequent to the failure. For example, if the failure occurred during the afternoon of a hot summer day the load demand was high, a high tap setting could lead to a high-voltage condition in the evening when the system load demand diminished and the grid voltage increased. Failures of the tap changer to change settings when demanded are less serious than active failures of the LTC, since the overvoltage or undervoltage 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, alarms alert the operator to high-voltage conditions on the 4160 V ESS buses, and procedures are in place to instruct the operators to take action to mitigate or correct the condition. The licensee has stated that its 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 manually change the tap setting if required.

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

The NRC staff agrees that, given the various features incorporated in to the LTC design and the expected reliability of the key features (i.e., primary controllers and backup controllers), the likelihood that an overvoltage will create a safety problem should be low.

The NRC staff had questions regarding the testing to be performed on the LTC transformer to demonstrate functionality; the response time of the LTC transformers (i.e., how fast can a tap change occur), and in the event of a voltage dip, the responsiveness of the LTC in preventing a trip of the degraded voltage relays.

In a letter dated January 13, 2006, the licensee stated that the LTC transformers for both Units 2 and 3 were recently installed. The Unit 2 transformer has been in service in the manual mode of operation for approximately 2 years, and the Unit 3 transformer was installed in November 2005. Both transformers were subjected to standard transformer tests during 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 alternating current impedance testing. Also, operation of the LTC on each transformer was verified over the full range of tap positions. For both Units 2 and 3, LTC transformer control circuits, controls, and control switches were verified to function properly in accordance with the applicable schematic diagrams. Also, the local and control room indications for the transformer LTC were checked for proper functionality. Testing of the main and backup controllers included verifying with a simulated voltage input that the LTC regulating relay provided the correct raise/lower response and the LTC backup relay provided the proper blocking function. Additionally, on a 2-year frequency, the LTC will be verified both manually and electrically for proper timing and sequencing of operation. On a 6-year frequency, preventive maintenance consisting of inspection of contacts for damage and pitting, checks for loose or damaged components, and functional testing of the LTCs (i.e., similar to the 2-year test) will be performed. The NRC staff finds the response acceptable.

With regard to the LTC response, the licensee stated that the regulating relays controlling the LTCs are set with an initial delay of 1 second (i.e., 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 2 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 the 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, after which, if the voltage does not recover, the safety buses will be disconnected from offsite power. If a loss-of-coolant accident occurs at full-power operations, it has been determined that two tap changes are required to support the additional continuous load on the transformer and compensate for the switchyard voltage drop due to loss of the unit. Considering the additional time needed for the 1-second initial delay before the two tap changes begin, the LTC will complete the 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 TS 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. The NRC staff finds this response acceptable.

Based on the above discussion, the NRC staff concluded that the licensee satisfied the applicable regulatory requirements and guidelines including GDCs 17 and 18.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Illinois State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change the requirements with respect to installation or use of a facility's components located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (70 FR 67747; November 8, 2005). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

8.0 Reference

1. Ltr from Bailey, S. N. (U.S. NRC) to Kingsley, O. D. (Commonwealth Edison Company), Issuance of Amendments, dated March 30, 2001.

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Date: March 17, 2006

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