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10 CFR 50.90
10 CFR 50.59

RS-05-037

April 4, 2005

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

Dresden Nuclear Power Station, Units 2 and 3
Renewed Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Subject: Request for License Amendment Regarding Offsite Power Instrumentation and Voltage Control

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 amendments to Renewed Facility Operating License Nos. DPR-19 and DPR-25 for Dresden Nuclear Power Station (DNPS), Units 2 and 3 and Appendix A, Technical Specifications (TS), of the Renewed Facility Operating License. The proposed changes revise TS Section 3.3.8.1, "Loss of Power (LOP) Instrumentation," and also revise the Updated Final Safety Analysis Report (UFSAR) to implement 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 revises the maximum and minimum allowable values for the degraded voltage function of the 4160 volt essential service system bus under-voltage instrumentation. 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 LTCs are subcomponents of new transformers that have been or 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. The LTC for DNPS, Unit 2 has been installed, with the only remaining work being the installation of manual raise/lower controls in the main control room. The LTC for DNPS, Unit 3 is an integral part of the new transformer scheduled for installation within the next 24 months.

The proposed change requests NRC approval to operate the LTCs in automatic mode. Both 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 changes.
- Attachment 2 provides the marked-up TS page with the proposed change indicated.
- Attachment 3 provides the re-typed TS page incorporating the proposed change.
- Attachment 4 contains the marked-up UFSAR pages with the proposed changes indicated.

The proposed changes have been reviewed by the DNPS 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 April 4, 2006. For Unit 2, the amendment will be implemented within 60 days following NRC approval of the proposed amendment. For Unit 3, the amendment will be implemented within 60 days following completion of installation and satisfactory testing of transformer 32.

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. Kenneth M. Nicely at (630) 657-2803.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 4th day of April 2005.

Respectfully,

Patrick R. Simpson

Patrick R. Simpson
Manager – Licensing

Attachment 1: Evaluation of Proposed Changes
Attachment 2: Marked-up TS Page with Proposed Change
Attachment 3: Re-typed TS Page with Proposed Change
Attachment 4: Marked-up UFSAR Pages with Proposed Changes

ATTACHMENT 1
Evaluation of Proposed Changes

1.0 INTRODUCTION

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 amendments to Renewed Facility Operating License Nos. DPR-19 and DPR-25 for Dresden Nuclear Power Station (DNPS), Units 2 and 3 and Appendix A, Technical Specifications (TS), of the Renewed Facility Operating License. The proposed changes revise TS Section 3.3.8.1, "Loss of Power (LOP) Instrumentation," and also revise the Updated Final Safety Analysis Report (UFSAR) to implement 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 revises the maximum and minimum allowable values for the degraded voltage function of the 4160 volt (V) essential service system (ESS) bus under-voltage instrumentation. 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 LTCs are subcomponents of transformers that have been or 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. The LTC for DNPS, Unit 2 has been installed, with the only remaining work being the installation of manual raise/lower controls in the main control room. The LTC for DNPS, Unit 3 will be included as part of the installation of a new transformer scheduled for installation within the next 24 months.

The proposed change requests NRC approval to operate the LTCs in automatic mode. Both 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.

2.0 DESCRIPTION OF PROPOSED AMENDMENT

<u>Revision to TS 3.3.8.1</u>
TS Table 3.3.8.1-1, "Loss of Power Instrumentation," Function 2.a, "Bus Undervoltage/Time Delay," requires that the maximum and minimum allowable values for the function be 3911 V and 3861 V, respectively. The proposed change revises the maximum and minimum allowable values to 3881 V and 3851 V, respectively, based on revised calculations.

<u>Revision to UFSAR</u>
The proposed UFSAR revision reflects implementation of the automatic operation mode of the LTCs. For Unit 2, the LTC is a subcomponent of transformer (TR) 86, which has been installed in the DNPS switchyard to provide offsite power from the 345 kilovolt (kV) transmission system to DNPS, Unit 2 through reserve auxiliary transformer (RAT) 22. For Unit 3, the LTC is a subcomponent of a new transformer that will replace the current RAT 32, which provides offsite power from the 345 kV transmission system to DNPS, Unit 3.

To reflect the incorporation of TR 86 and its LTC into the DNPS design, and the replacement of TR 32 with a new transformer and LTC, changes to the following DNPS UFSAR sections are proposed.

- Section 8.2.2.2, "Stability Analysis"
- Section 8.3.1.2.2.1, "Reserve Auxiliary Transformer"
- Table 8.3-1, "Auxiliary Electrical System Equipment Listing"

The UFSAR descriptions of TR 86, TR 32, and the LTCs are included in Attachment 4. The UFSAR descriptions of the TR 86 and TR 32 installations are provided for information only, since they do not require NRC approval in accordance with 10 CFR 50.59. Additional pages of the UFSAR have been or will be revised as part of the installation of TR 86 and the planned installation of TR 32. These pages are not provided, since they do not relate directly to the proposed changes for the automatic mode of LTC operation.

The marked-up UFSAR pages included in Attachment 4 include changes that have already been approved in accordance with EGC's UFSAR change process through change package 03-013. EGC is not requesting NRC approval of the changes annotated with "03-013" in the right margin.

3.0 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 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, 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.

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, DNPS 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 (i.e., TR 86). To provide voltage regulation capability, 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 is not currently equipped with an LTC.

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 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, or 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. 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 the 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 voltages (with the same operational contingencies used for planning purposes) would be maintained between 101% and 105% of the nominal voltage on the 345 kV system, or 348.5 kV to 362.3 kV through June 1, 2004. Following June 1, 2004, with the transition to the PJM network, the transmission system planning criteria described above were implemented.

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.

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% of nominal) met the DNPS requirements for operability of offsite power. However, the minimum transmission planning criteria voltage (i.e., 98% of nominal) and the emergency criteria (i.e., 95% 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 unforeseen 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 determine 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 different days for DNPS Unit 3, indicating that the predicted post-trip voltage was below the minimum required to ensure the 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, DNPS initiated actions to procure a replacement for TR 32 that is equipped with an LTC, and to seek approval for use of 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.

Additionally, DNPS proposes to slightly reduce the maximum and minimum allowable values for the degraded voltage relay. Reducing these values, in accordance with the EGC setpoint methodology that was previously reviewed and accepted by the NRC for DNPS in Reference 1, will allow a reduction of the relay reset value. The relay reset value is not part of the DNPS TS, but is based on the field setpoint, which is based on the allowable values. Following actuation of the degraded voltage relay timer, ESS bus voltage must rise to a value above the reset value in order to avoid actuation of the degraded voltage relay. The reduced reset value will allow the offsite circuit to remain operable with a slightly lower switchyard voltage. This will continue to ensure that adequate voltage is maintained to safety-related equipment, while preventing unnecessary actuation of the degraded voltage relays.

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% to 105% of nominal).

4.0 REGULATORY REQUIREMENTS & GUIDANCE

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 assure 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.

DNPS Technical Specifications (TS), Sections 3.8.1, "AC Sources – Operating," and 3.8.2, "AC Sources – Shutdown," require that two qualified offsite power sources be operable in Modes 1,2, and 3, and one qualified offsite power source be operable in Modes 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment, respectively.

To satisfy Criterion 17 of the General Design Criteria (GDC) and the TS, 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 50.36, "Technical specifications," requires that limiting conditions for operation be established for structures, systems, and components that are part of the primary success path and which function to mitigate a design basis accident. The LOP instrumentation functions to mitigate a loss of offsite power (LOOP) and thus a limiting condition for operation is required.

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 5.0 below, 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.

5.0 TECHNICAL ANALYSIS

Revision to TS 3.3.8.1

The LOP instrumentation monitors the 4160 V ESS buses to ensure that adequate voltage is available for the components required to mitigate accidents. Each Division 1 and 2 4160 V ESS bus degraded voltage function is monitored by two under-voltage/time delay relays, whose outputs are arranged in a two-out-of-two logic configuration. During normal (i.e., non-accident) operation, when a degraded voltage function setpoint has been exceeded and persists for seven seconds (i.e., the inherent time delay of the relay) on both relay channels, a control room annunciator alerts the operator of the degraded voltage condition and the five minute time delay function timer is initiated. If the degraded voltage condition does not clear within five minutes, the five 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 five minute time delay function is bypassed such that load shedding and the associated DG start will be initiated following the seven second inherent time delay.

The minimum allowable value for the degraded voltage relay is determined as follows. A detailed analysis is performed to determine the minimum voltage (i.e., analytical limit) 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 allowable voltage values and corresponding relay setpoints and associated tolerances.

The maximum allowable value does not have an analytical limit needed to provide a safety function. The maximum allowable value is determined from the analytical limit for the minimum allowable value and the uncertainties. This provides a reasonable operating band that does not result in unnecessary actuation of the relays.

The degraded voltage setpoint calculations have been revised to reduce the total uncertainty while maintaining the existing analytical limit for the minimum value. This change was accomplished by reclassifying the potential transformer (PT) uncertainty term from non-random to random in accordance with EGC setpoint methodology. Previously, this term had been considered a non-random source of uncertainty because this treatment has the effect of maximizing the estimation of total uncertainty. This treatment has been changed for the following reasons. First, the PT is a separate device whose output provides measurement of actual ESS bus voltage to the degraded voltage relay. Second, the actual uncertainty of the PT term is unknown, but is bounded at +/- 0.3%, which is the ANSI/IEEE Standard C57.13, "IEEE Standard Requirements for Instrument Transformers," accuracy rating of the PT. Finally, the PT uncertainty is not part of the uncertainty present during calibration of the degraded voltage relay. Therefore, the uncertainty of the PT is now considered to be an independent random term. Based on this re-classification, revised allowable values were determined in accordance with the EGC setpoint methodology, which was previously reviewed and accepted by the NRC for DNPS in Reference 1. The revised calculation results in reduced values for both the maximum and minimum allowable values (i.e., 3881 V and 3851 V, respectively) for Table 3.3.8.1-1, Function 2.a.

UFSAR Revision

Description of Transformer and LTC Modifications
The modification to add TR 86 and transfer the RAT 22 source to the 345 kV system using TR 86 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 modification to replace the current RAT 32 with a new transformer containing an LTC will be similarly evaluated in accordance with 10 CFR 50.59 for use in manual operation.

TR 86, which was installed in October 2003, is a 100 mega-volt-ampere (MVA) 345/138 kV transformer with an LTC. The LTC will regulate voltages to the plant RAT 22 transformer. The currently-installed RAT 32 is 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. The MVA ratings of TR 86 and TR 32 are not the same because TR 86 is a substation auto transformer that has been conservatively sized.

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 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.

For TR 86, the LTC will provide a range of +/- 10% of the rated voltage in 33 steps, each step being 0.625 %. TR 86 also contains a fixed ratio, de-energized 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 +/- 15% of nominal. The LTC has sufficient range to respond to the expected 345 kV system range of 95% to 105% of nominal.

For TR 32, the LTC will provide a range of +25%/-5% of the rated voltage in 33 steps, each step being 0.9375 %. Thus, the tap changer is expected to be able to compensate for the expected switchyard voltage range of 95% to 105% of nominal voltage. 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 providing automatic adjustment of 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.

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 DNPS 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 extremely unlikely, and operator action can be taken to prevent a sustained high voltage condition. Furthermore, as discussed in Section 7.0 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 over ride 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.

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 control room 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 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 respond under the guidance of established abnormal operating procedures upon receipt of the 4160 V ESS bus over-voltage alarm. The procedural guidance directs operator to take manual control of the LTC. The tap setting can then be manually lowered from the control room 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 setpoint of 3874 V. Failure to restore the bus voltage within 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 4000 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 are in place 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 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
The revision to the allowable values for the LOP instrumentation will continue to ensure that adequate voltage is maintained to safety-related equipment, while preventing unnecessary actuation of the degraded voltage relays. 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 DNPS, Units 2 and 3 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 DNPS, Units 2 and 3.

6.0 REGULATORY ANALYSIS

As demonstrated in Section 5.0 above, revision of the allowable values for TS 3.3.8.1, Function 2.a and usage of the LTC automatic operation mode for TR 86 and TR 32 will ensure that the offsite power capabilities of DNPS 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 TS requirements.

7.0 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 DNPS, Units 2 and 3 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 proposed changes revise the Technical Specifications (TS) maximum and minimum allowable values for the degraded voltage protection function and implement the use of automatic load tap changers (LTCs) on transformers that provide power to safety-related equipment. The only accident previously evaluated for which the probability is potentially affected by these changes is the loss of offsite power (LOOP). An allowable value for the degraded voltage protection function that is too high could cause the emergency buses to transfer to the emergency diesel generators and thus increase the probability of a LOOP. The allowable value for the degraded voltage protection function has been revised in accordance with an NRC-approved setpoint methodology and will continue to ensure that the degraded voltage protection function actuates when required, but does not actuate prematurely to cause a LOOP.

A failure of an LTC while in automatic operation mode that results in decreased voltage to the ESS buses could also 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 highly 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 changes will have 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 changes.

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

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 caused a sustained high voltage which resulted in damage to safety related equipment that is used to mitigate an accident. Damage due to over-voltage is time-dependent. Since the LTC is equipped with a backup controller, and since operator action is available to prevent a sustained high voltage condition from occurring, damage to safety related equipment is extremely unlikely, and thus the consequences of these accidents are not significantly increased.

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 changes involve functions that provide offsite power to safety related equipment for accident mitigation. Thus, the proposed changes potentially affect the consequences of previously evaluated accidents (as addressed in Question 1), but do 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 changes do 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 have been revised in accordance with an NRC-approved setpoint methodology 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 changes do not involve a significant reduction in a margin of safety.

Based upon the above, EGC concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR50.92(c), and, accordingly, a finding of no significant hazards consideration is justified.

8.0 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.

9.0 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 2 and 3, respectively.

10.0 IMPACT ON PREVIOUS SUBMITTALS

EGC has reviewed the proposed changes for impact on previous submittals awaiting NRC approval for DNPS, and has determined that there is no impact.

11.0 REFERENCES

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

2. 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

3. 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 Technical Specifications Page with Proposed Change

<u>Page</u>
3.3.8.1-3

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4160 V Essential Service System Bus Undervoltage (Loss of Voltage)	2	SR 3.3.8.1.3 SR 3.3.8.1.4 SR 3.3.8.1.5	≥ 2796.85 V and ≤ 3063.20 V
2. 4160 V Essential Service System Bus Undervoltage (Degraded Voltage)			3851 3881
a. Bus Undervoltage/Time Delay	2	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.5	≥ 3861 V and ≤ 3911 V with time delay ≥ 5.7 seconds and ≤ 8.3 seconds
b. Time Delay (No LOCA)	1	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.5	≥ 279 seconds and ≤ 321 seconds

ATTACHMENT 3
Re-Typed Technical Specifications Page with Proposed Change

Page
3.3.8.1-3

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4160 V Essential Service System Bus Undervoltage (Loss of Voltage)	2	SR 3.3.8.1.3 SR 3.3.8.1.4 SR 3.3.8.1.5	≥ 2796.85 V and ≤ 3063.20 V
2. 4160 V Essential Service System Bus Undervoltage (Degraded Voltage)			
a. Bus Undervoltage/Time Delay	2	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.5	≥ 3851 V and ≤ 3881 V with time delay ≥ 5.7 seconds and ≤ 8.3 seconds
b. Time Delay (No LOCA)	1	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.5	≥ 279 seconds and ≤ 321 seconds

ATTACHMENT 4
Marked-up UFSAR Pages with Proposed Changes

The auxiliary power supply for Unit 3 is split between UAT 31, which is connected to the generator leads, and RAT 32, which is connected to the 345-kV switchyard.

The auxiliary transformers (UAT and RAT) step the generator and transmission voltages, down to the station 4160-V system level.

345-kV is

The auxiliary power supplies from the ~~138-kV and~~ 345-kV transmission system~~s~~ ~~are~~ protected against the effect of unplanned outages by the diversity of seven separate 345-kV circuits, ~~six 138-kV circuits,~~ and two major generating units feeding into the ~~two~~ switchyard~~s~~ at the Dresden site. Each unit has adequate auxiliary power available from ~~either~~ the ~~138-kv or~~ 345-kV switchyard or from the diesel generators. 03-013

Protection of the RATs, including their secondary circuits and devices, from lightning and surges is provided by surge arresters applied on the primary side of the transformers.

in the

The failure of any one component ~~of either the 138-kV or~~ 345-kV transmission systems would not cause a simultaneous outage of both buses at Dresden. 03-013

8.2.2 Analysis

The CECo transmission network has been designed to maintain availability at acceptable levels. Analyses have been performed to demonstrate that electrical failures in the network would not result in unstable operation.

8.2.2.1 Availability Considerations of the Transmission Network

The offsite power sources provide sufficient capacity and capability (see Section 8.3) to start and operate safety-related equipment. This ensures that the fuel design limits and the design conditions of the reactor are not exceeded during normal operation and that the reactor core can be cooled and maintained in a safe condition in the event of postulated accidents. Because the sources to the site are normally energized, they are immediately available to the station.

The offsite power sources for the station auxiliary power system provide redundancy, as well as electrical and physical independence, so that any single failure can affect only one source of supply and cannot propagate to alternate sources. While it is highly unlikely that all transmission lines could be out-of-service simultaneously, such an event would not jeopardize safe shutdown of the station because the onsite standby diesel generators would be able to supply the necessary power to the systems required for safe shutdown (see Section 8.3).

One of the functions of MAIN is to ensure that the transmission system is reliable and adequate. Power flow and transient stability studies are conducted on a regular basis using the criteria stated in MAIN Guide No. 2.[1]

The transmission system at CECo is designed to meet all the criteria listed in the MAIN Guide No. 2.

MAIN Guide No. 2 stipulates that the generation and transmission system shall be adequate to withstand the most severe of the identified set of contingencies without resulting in an uncontrolled widespread tripping of lines and/or generators with resulting loss of load over a large area.

The reliability of the transmission grid is demonstrated by the performance data of the 345-kV transmission lines. The average 345-kV line in the MAIN grid experienced approximately 1.6 forced outages per year, with an average duration of approximately 42 hours per forced outage during the period from 1987 to 1990, approximately 627 line-years of exposure. For the 4 years between January 1, 1987, and December 31, 1990, the average CECo 345-kV line experienced approximately 1.5 forced outages per year, with an average duration of approximately 53 hours per forced outage. This period represents approximately 366 line years of experience. The percentage of forced outages due to various causes is listed in Table 8.2-1. 03-013

The ability of the CECo transmission system to withstand the loss of transmission lines connecting the Dresden switchyards to the network has been investigated through separate stability studies for each station to demonstrate adequacy of the transmission system. The electric systems in Wisconsin, Iowa, Illinois, and Indiana were all represented in lesser detail.

8.2.2.2 <u>Stability Analysis</u>

An analysis was made to determine the response of the external power grid to the sudden loss of both Dresden Units 2 and 3 (the worst case as compared to the loss of only one unit) and the effects on the availability of offsite power. The conclusion of this study was that the external power system would be able to supply the station requirements continuously both immediately after the loss of both units and later when generation on the power system is readjusted to make up the lost generation. The design of the offsite power system is in compliance with NRC General Design Criterion (GDC) 17.

Figures 8.2-4, 8.2-5A, and 8.2-5B show the typical power flows in the Dresden area before the loss of the Dresden generation. These calculations were made by a digital computer load flow program and simulate projected peak load conditions on the interconnected system in 1997.

Figures 8.2-6, 8.2-7A, and 8.2-7B show corresponding typical power flows in the Dresden area following the sudden loss of both Dresden Units 2 and 3. These units had been generating a total of 1623 MW gross (1545 MW net) before the outage. For the condition shown in Figures 8.2-6, 8.2-7A, and 8.2-7B, the energy previously generated by Dresden Units 2 and 3 is made up by the release of kinetic energy of the other generators on the interconnected system resulting in incremental power flow from other systems. This is a momentary condition which could exist only until automatic governor action would begin to increase generation tending to decrease loading on ties. Analysis of the loadings shown in Figures 8.2-6, 8.2-7A, and 8.2-7B indicated no overloads or line loadings which would cause relay tripping. 03-013

~~Figures 8.2-8, 8.2-9A, and 8.2-9B show the corresponding typical power flows after generation on the CECo system has been adjusted to replace the lost generation. This condition would be reached several minutes after the Dresden units had tripped. The needed additional capacity will largely be obtained from spinning reserve on the system.~~

03-013

The auxiliary power supply from the 345-kV transmission system is protected against the effect of unplanned outages by the diversity of the separate 345-kV and 138-kV circuits and two major generating units feeding into a ring bus in the switchyards at the station (see Figures 8.2-1 and 8.2-2).

seven

As a result of an NRC request, a site-specific analysis was made to determine system voltages under various system conditions, including severely degraded conditions.

Through the analysis CECo determined the following:

A. The maximum expected load terminal voltages occur when the switchyard voltage is maximum and there are no unit loads;

B. The minimum expected continuous load terminal voltages (when not sharing an offsite power source) occur when the switchyard voltage is at a minimum and, except for those loads automatically shed due to a unit trip, the auxiliary bus loads and the Class 1E loads are maximum; and

INSERT 1

C. The minimum expected transient load terminal voltages occur under the conditions of item B above, concurrent with the start of a large load.

~~The normal range of operating voltages on the CECo transmission system supplying offsite power to Dresden Station is summarized in the system planning department operating guides.~~

~~An additional analysis was performed by the CECo System Planning Department assuming 18,500 MW system load with Unit 3 at maximum reactive power output. This analysis was performed to determine the effect of a Unit 3 generator trip (from full power) on the offsite power source voltage to the Unit 3 RAT. Results indicated that the worst-case voltage drop would be 9-kV (from 354-kV to 345-kV) or approximately 2.5%, which is consistent with current power flow analysis. Additionally, the analysis indicated that closing of the 345-kV switchyard crosstie breaker post-trip would result in restored voltage to 351-kV.~~

~~It should be noted that a trip of Dresden Unit 2 main generator from full power has minimal affect, if any affect on the Unit 2 source of offsite power. The Unit 2 RAT normal feed is from a 138-kV transmission system which is electrically separated from the Unit 2 main power transformer 345-kV bus connection.~~

03-013

With respect to the requirements of GDC-17, these results indicate that the possibility of losing electric power from the transmission network due to the loss of power generation from a unit is minimal.

Insert 1

Periodic studies are performed to ensure that the offsite power system voltage remains adequate to ensure the reliability of offsite power to the Dresden units.

The unit's RAT is the primary offsite source to the essential service system (ESS) buses. The RAT of the other unit provides a second offsite power source through a bus tie provided between corresponding ESS buses of the two units. Additionally, the UAT of either unit provides another source of offsite power to the ESS buses only when the unit is shutdown and the UAT is being back fed from the grid. Physical changes to the generator links are required to place the plant in an alignment to allow backfeed. There are manual crosstie connections between buses 23-1 and 33-1 and between buses 24-1 and 34-1 which may be used to supply power from one unit to the other under abnormal conditions. Bus 40 is shared between the units and is the mechanism by which standby diesel generator 2/3 supplies either bus 23-1 or 33-1. Because of the configuration of the control circuitry, under normal conditions bus 40 does not supply power to both units simultaneously. However, procedural provisions exist that allow bus 40 to feed both units simultaneously if conditions warrant such an alignment.

A partial firewall with an open accessway is installed between the 4160-V switchgear 23-1 and 24-1 to prevent fire from spreading from one switchgear area to the other for Unit 2. A similar barrier is also installed between switchgear 33-1 and 34-1 for Unit 3.

8.3.1.2.2 System 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.

345-kV through TR86 to

8.3.1.2.2.1 Reserve Auxiliary Transformer

The RAT (TR22 for Unit 2 and TR32 for Unit 3) steps switchyard voltage (138-kV for TR22 and 345-kV for TR32) down to 4160-V for use with station auxiliary loads. The ratings of the RATs can be found in Table 8.3-1. The primary (138-kV or 345-kV) winding and each of the two secondary windings (4160-V) for either RAT are grounded-wye connected.

and TR86

8.3.1.2.2.2 4160-V Switchgear

INSERT 2

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 a metal-clad indoor type and is located in both the reactor and turbine buildings. Flow deflectors have been installed above buses 23-1 (33-1) and 24-1 (34-1) to assure that any leakage from piping which runs above the switchgear will not impinge on the switchgear. Buses 23 (33) and 24 (34) do not have piping overhead and therefore do not need similar protection.

8.3.1.2.2.3 Circuit Breakers

Circuit breakers provide a means for isolating loads and power supplies from the 4160-V buses. Typical current ratings for 4160-V circuit breakers are 1200A, 2000A, and 3000A. Circuit breakers for the 4160-V system are three pole, electrically operated, with a 125-Vdc stored energy closing mechanism. Maintenance of 4160-V breakers is performed in accordance with Dresden

Insert 2

TR86 is a 345kV to 138kV auto transformer. When operating in its automatic mode, the automatic load tap changer (LTC) raises and lowers voltage by operation of the tap changer via the LTC controller. The combination of a fixed-ratio (no load) tap changer and the automatic LTC determines the overall range of the TR86 output. The automatic LTC on TR86 will provide a range of +/- 10% of the rated voltage in 33 steps, each step being 0.625%. The fixed ratio/no load tap changer, which can only be changed when TR86 is de-energized, has five taps or positions. Each tap corresponds to a voltage difference of 2.5% in five steps for a range from -5% to +5% of nominal. Therefore, the full potential range of the transformer is +/- 15% with adjustments to optimize the no load tap.

TR32 is a 345-4.264-4.264 kV three winding transformer with an LTC on the 4.264 kV X-winding. The LTC on TR32 will provide a range of +25% to -5% of the rated voltage in 32 steps, each step being approximately 15/16% of rated voltage. The LTC may be operated manually or in 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 (insert amendment numbers upon approval) 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 TR86 or TR32. 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.

Table 8.3-1

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

<u>TRANSFORMER</u>	
TR2 Main Power	850-MVA (55°), 17.1 — 345 kV, 1050 kVBIL, 3φ, 60Hz, FOA, 55°/65° Rise
TR20	1000 kVA, 4160 — 480-V, 3φ, 60Hz.
TR21(31) Unit Auxiliary Power (Unit 3 data is in parenthesis)	27.6/36.8/46-MVA, 55°C; 17.1 — 4.16 — 4.16 kV 150 kVBIL, 3φ, 60Hz, OA/FA/FOA, 55°/65° Rise Impedance: H - X = 6.64(6.92)% (on a 11.4-MVA base) H - Y = 7.16(7.45)% (on a 16.2-MVA base) X - Y = 11.4(11.9)% (on a 11.4-MVA base) Winding Ratings: H - 27.6/36.8/46-MVA (55° rise) X - 11.4/15.2/19-MVA (55° rise) Y - 16.2/21.6/27-MVA (55° rise)
TR22~~(32)~~ Reserve Auxiliary Power ~~(Unit 3 data is in parenthesis)~~	27.6/36.8/46-MVA, 50°C; 138~~(345)~~ — 4.16 — 4.16 kV 550~~(1050)~~ kVBIL, 3φ, 60Hz, CA/FA/FA~~(OA/FA/FOA)~~, 55°/65° Rise Impedance: H - X = 6.4% (on an 11.4-MVA base) H - Y = 7.5~~(7.19)~~% (on a 16.2-MVA base) X - Y = 11.6~~(12.14)~~% (on an 11.4-MVA base) Winding Ratings: H - 27.6/36.8/46-MVA (55° rise) X - 11.4/15.2/19-MVA (55° rise) Y - 16.2/21.6/27-MVA (55° rise)
INSERT 3	
TR25, TR26, TR27, TR28 and TR29	1500/1725 kVA, 4160 — 480/277V, 3φ, 60Hz, OA/OF, 55°/65°C Rise Min. Impedance 10.91%, Max. Impedance 11.09% @ 1500
<u>CIRCUIT BREAKERS</u>	
4160 V Bus 40	
Incoming	None
Feeders	AM 4.16 — 250-MVA, 1200 A
4160 V Buses 21 and 22	
Incoming	AM 4.16 — 350-MVA, 3000 A
Feeders	AM 4.16 — 350-MVA, 1200 A
4160 V Buses 23 and 24	
Incoming	AMHG 5-350-20 — 350-MVA, 2000 A
Feeders	AMHG — 350-MVA, 1200 A
Bus Tie	AMHG — 350-MVA, 1200 A
Spares	AMHG 5-351-12 — 350-MVA, 1200 A
4160 V Buses 23-1 and 24-1	
Incoming	4 - AMH 4.76 — 250-MVA, 1200 A
Feeders	9 - AMH 4.76 — 250-MVA, 1200 A
Bus Tie	4 - AMH 4.76 — 250-MVA, 1200 A

Insert 3

TR32 Reserve Auxiliary Power Transformer	37.5/50/62.5 MVA, 345-4.264-4.264 kV, 3ϕ, 60 Hz, ONAN/ONAF/OFAF, 1050/75/75kV BIL, 65°C rise Winding Ratings: H - 37.5/50.0/62.5-MVA (65°C Rise) X - 18.75/25.0/31.25-MVA (65°C Rise) Y - 18.75/25.0/31.25-MVA (65°C Rise) X - Winding Load Tap Changer (LTC): Full Capacity, +16/-16 Positions at 0.938% Resultant +25%/-5% of Rated Winding Voltage
TR86	100 MVA (55°C), 345-138 kV, 3ϕ, 60 Hz, ONAN/ONAF/ONAF, 1050kV BIL, 55°/65° C rise, LTC +/- 10%