CP&L
Carolina Power & Light Company

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United States Nuclear Regulatory Commission
ATTENTION: Document Control Desk
Washington, DC 20555

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 & 50-324/LICENSE NOS. DPR-71 & DPR-62
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION RELATED TO THE SCRAM ON SEPTEMBER 27, 1990 (TAC. NOS. 79628 AND 79629)

Gentlemen:

On September 27 1990, the Brunswick Steam Electric Plant (BSEP), Unit 2, scrammed while operating at 100 percent power. On October 26, 1990, Carolina Power & Light Company (CP&L) submitted Licensee Event Report (LER) 2-90-25 to the NRC staff describing this event.

CP&L has received your letter, dated May 30, 1991, requesting additional information necessary to allow the staff to establish the adequacy of the BSEP offsite and onsite power systems. The requested information is provided in the enclosure to this letter in the form of specific responses to the questions delineated in Enclosure 1 to your May 30, 1991 letter concerning this issue.

Please refer any questions regarding this submittal to Mr. M. R. Oates at (919) 546-6063.

Yours very truly,

S. D. Floyd

S. D. Floyd
Manager
Nuclear Licensing Section

SDF/JCP

Enclosure

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ENCLOSURE 1

BRUNSWICK STEAM ELECTRIC PLANT, UNITS 1 AND 2
NRC DOCKETS 50-325 & 50-324
OPERATING LICENSES DPR-71 & DPR-62
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION RELATED TO
THE SCRAM ON SEPTEMBER 27, 1990 (TAC. NOS. 79628 AND 79629)

NRC QUESTION NO. 1

It is not clear why, during the above event, the onsite power supply (UAT) was not transferred to the preferred offsite power source (SAT) via a fast transfer scheme at the BOP bus before the undervoltage relays initiated load shedding on both emergency buses E3 and E4. Explain how the bus transfer schemes at the BOP buses are designed to work in connection with undervoltage transients like the above event. Are there any design modifications considered as a result of the above event?

CP&L RESPONSE TO QUESTION NO. 1

The automatically initiated, automatically executed fast dead bus transfer scheme (from the UAT to the SAT) is initiated by the main generator / main transformer lockout relays (86G, 86GB, and 86GP). Several signals can cause actuation of the lockout relays. These include generator differential current, loss of field, directional distance, reverse power and ground, and also UAT and main transformer fault pressure and differential current. Actuation of the lockout relays initiates tripping of the switchyard breakers which connect the main transformer to the switchyard buses and simultaneously initiates the fast dead bus transfer scheme. Undervoltage relays do not provide signals to actuate the generator / main transformer lockout relays. The UAT breaker to the BOP bus will trip when an undervoltage condition occurs, but the SAT breaker to that bus does not receive an automatic close signal. The Class 1E undervoltage relays (27/59E) at the emergency buses: 1) trip motor feeder breakers motor protection, 2) trip tie breakers, and 3) provide an EDG breaker close permissive.

In the September 1990 event, the exciter failure resulted in an undervoltage condition which was sensed by the emergency bus undervoltage relays before the reverse power relay actuated. This resulted in the load shedding at the emergency buses prior to the fast bus transfer at the BOP buses.

CP&L is investigating the function of the undervoltage relays and is evaluating the need for modifications as a result of the event. Transferring the auxiliary electrical distribution system to the SAT during this event would not have prevented voltage perturbations on the auxiliary electrical distribution system. The main generator, due to a malfunctioning regulator, was causing severe voltage perturbations, not only on the plant distribution system, but also throughout CP&L's transmission system. As long as the generator was connected to the grid (switchyard), these same voltage swings would have occurred, even if the auxiliary electrical distribution system had transferred to the preferred power source (SAT). Research performed in the

design basis reconstitution program should establish the basis for this design.

NRC QUESTION NO. 2

Explain why the loss of voltage (LOV) relays (27/59E), which do not start emergency diesel generators (EDGs), are included in Table 3.3.3-1 of the Brunswick Technical Specifications (TS). It appears from your design that the 27HS relays which start the EDGs on the safety buses perform the LOV function rather than 27/59E. Provide the basis for not including 27HS undervoltage relays in Table 3.3.3-1 of TS.

CP&L RESPONSE TO QUESTION NO. 2

Amendments 28 (Unit 1) and 51 (Unit 2) added Technical Specification Table 3.3.3-1 to the Brunswick Technical Specifications. CP&L requested these amendments as a result of an NRC letter dated June 3, 1977 which required licensees to incorporate Technical Specifications for the plant undervoltage protection equipment. The NRC found the proposed changes acceptable based on a report entitled "Technical Evaluation Report of the Degraded Grid Protection for Class 1E Power Systems at the Brunswick Steam Electric Plant, Unit Nos. 1 and 2" dated February 1980, by EG&G Idaho.

The two primary functions of the 27/59E relays are:

1. initiate tripping of all 4.16 kv emergency bus load feeder breakers (with the exception of the emergency substation feeder), and tie breakers (typically open)

2. supply a "dead bus" permissive signal to the emergency diesel generator breaker closing circuitry to ensure that the EDG does not connect to a "hot" bus.

During loss of voltage or severely degraded voltage conditions, the 27/59E relays provide motor protection by tripping the associated feeder breakers. The 4.16 kv emergency bus 27/59E relays fulfill the undervoltage protection function at Brunswick and, as such, were the relays listed in Table 3.3.3-1 by Amendments 28 (Unit 1) and 51 (Unit 2).

The 27HS relay does not provide the undervoltage protection function; it is one of several EDG start initiators associated with the power system as listed below:

Diesel Generator Start Initiator Paths

1. Device 86GP (main generator trip)

2. Device 86TBX (230 KV bus, MOD, and SAT differential)

3. Device 86ST (SAT differential)

4. Device 27/59S (SAT undervoltage)

5. Device 27/59U (UAT undervoltage)

6. Device 86G2 (main generator trip)

7. Both emergency bus tie breakers and the BOP feeder breaker to the emergency bus tripped in conjunction with the EDG not running in manual

8. 27HS (12HGA17C63 relay-voltage loss at the emergency bus)

Items 1 through 6 will initiate either a divisional EDG start (i.e., EDGs 1 & 3 or EDGs 2 & 4) or a four EDG start depending on which device actuates.

Items 7 or 8 will initiate starts on the EDGs associated with the respective emergency bus.

Although the 27HS relay provides an EDG start initiation signal for power system failures or degraded voltage conditions it is not the actual undervoltage protection device. Therefore, the 27HS relay was not required to be incorporated into the Technical Specifications in accordance with the NRC's June 3, 1977 letter.

NRC QUESTION NO. 3

The voltage sensing relays (27/59S & 27/59U), which are located on the BOP buses (2C & 2D) start the EDGs during undervoltage conditions. Justify why a Class 1E function is performed by the non-Class 1E relays.

CP&L RESPONSE TO QUESTION NO. 3

The 27/59S & 27/59U relays have multiple functions. The functions of the 27/59S relay include:

a. tripping the SAT incoming line breaker to the 4.16 kv BOP bus upon detection of loss of voltage (assuming it was closed at the time of relay actuation)

b. precluding closing of the SAT incoming line breaker to the BOP bus if voltage is not available from the SAT (PT is connected on the transformer side of the incoming line breaker)

c. initiates starting of all EDGs and the two Nuclear Service Water Pumps associated with the train experiencing the problem (doesn't matter if the bus is being powered from the SAT or UAT at the time)

d. in conjunction with the 4.16 kv bus undervoltage relay (27), initiates stripping of motor load feeder breakers (in the scenario of feeding the bus from the SAT, both the 27 and 27/59S relays would have to actuate). This circuit requires that: (1) both the UAT and the SAT incoming line breakers be open along with the 27 relay indicating loss of voltage on the bus itself or (2) the transformer undervoltage relay (e.g. 27/59S)

associated with the incoming line breaker which is supplying the bus (e.g. SAT) be indicating no voltage from that transformer along with the 27 relay indicating loss of voltage on the bus itself.

e. acts as a permissive to the BOP 27HS relay for initiating starting of two EDGs associated with train experiencing problem and separation of the two related emergency buses from offsite power (will not happen if 27HS indicates loss of bus voltage but voltage is available from the UAT by closing the UAT incoming line breaker).

f. initiates tripping of load feeder breaker to associated emergency bus upon loss of voltage from the SAT and a LOCA has occurred.

g. prohibits closing of the load feeder breaker to associated emergency bus if voltage from SAT is unavailable and a LOCA has occurred.

The functions of the 27/59U relay include:

a. tripping the UAT incoming line breaker to the 4.16 kv BOP bus upon detection of loss of voltage (assuming it was closed at the time of relay actuation)

b. precluding closing of the UAT incoming line breaker to the BOP bus if voltage is not available from the UAT (PT is connected on the transformer side of the incoming line breaker)

c. in conjunction with the 4.16 kv bus undervoltage relay (27), initiates stripping of load feeder breakers (in the scenario of feeding the bus from the UAT, both the 27 and 27/59U relays would have to actuate). This circuit requires that: (1) both the UAT and the SAT incoming line breakers must be open along with the 27 relay indicating loss of voltage on the bus itself, or (2) the transformer undervoltage relay (e.g. 27/59U) associated with the incoming line breaker which is presently supplying the bus (e.g. UAT) be indicating no voltage from that transformer along with the 27 relay indicating loss of voltage on the bus itself.

d. acts as a permissive to the BOP 27HS relay for initiating starting of two EDGs associated with train experiencing problem and separation of the two related emergency buses from offsite power (will not happen if 27HS indicates loss of bus voltage but voltage is available from the SAT by closing the SAT incoming line breaker).

Under normal conditions the emergency buses are powered from the BOP buses. The function of the 27/59S and 27/59U relays is to provide an anticipatory start signal to the EDGs when an undervoltage condition occurs on the BOP buses. The emergency bus loss of voltage relays which start the EDGs are the emergency bus 27HS relays which are safety-related. The design basis reconstitution program should provide the basis for this design.

NRC QUESTION NO. 4

If the offsite power voltage drops to a level that is inadequate to start safety-related loads, will the 10.5 seconds degraded voltage relay time delay result in a delaying safety bus transfer to the diesel generators such that the plant may be outside the boundary of its safety analysis?

CP&L RESPONSE TO QUESTION NO. 4

Calculation BNP-E-3.001, Rev. 0 indicates that the maximum permissible time delay for the emergency bus degraded voltage relays (including tolerance) is 11.92 seconds. This will ensure that the maximum allowable time delays addressed in the Chapter 15 accident analysis will be met. Assuming that the relay actuates in 11.92 seconds, it would conservatively take an additional 0.1 seconds for the incoming line breaker to trip, 1.575 seconds for the 27/59E relay to actuate, and 0.2 seconds for the EDG supply breaker to close (after receiving a "permissive" from the 27/59E relay). Additionally, a 0.1 second safety margin is included in BNP-E-3.001, Rev. 0, as well as an additional 0.1 seconds for tripping the emergency bus load feeder breakers. This is conservative since the load feeder breakers receive the trip signals simultaneously with the EDG breaker receiving the permissive signal. This means that, conservatively, the bus would be re-energized in a maximum of 14 seconds. The limiting FSAR Chapter 15 accident analysis allowable time is 40 seconds after LOCA initiation to establish Core Spray flow. The Core Spray Pump gets a start signal at 16.5 seconds (maximum) and takes 3.1 seconds (maximum) to accelerate, which means that the pump would be up to speed in 33.6 seconds maximum (14.0 + 16.5 + 3.1). The Core Spray injection valves get a signal to open at 11 seconds (maximum) and take 15 seconds to open, which means that the injection valves would be properly aligned in 40 seconds maximum (14.0 + 11.0 + 15.0). The above discussion assumes the worst case condition of a simultaneous LOCA and degraded voltage condition.

NRC QUESTION NO. 5

We recognize that the grid voltage profile at Brunswick has changed since the plant was licensed due to capacity additions and load growth in the CP&L system. Therefore, provide the results of your analysis that demonstrate, as committed in Section 8.2.2 of the FSAR, that the loss of a Brunswick unit would not cause any cascading transmission outages or stability problems.

CP&L RESPONSE TO QUESTION NO. 5

There have been no significant capacity additions on the CP&L system in the vicinity of the Brunswick Plant since the plant was brought on line. The only generation addition in the area has been Cogentrix plant near Southport, but this facility has minimal impact on loadings on the transmission system and stability of the Brunswick or nearby Sutton Plant units. Without significant generation additions in the area, both the capability of the transmission system and the stability of the units in the area remains basically the same as initially designed. Load growth in the Wilmington area has the effect of improving the stability of the Brunswick and Sutton units since the equivalent

load center in the area is now closer to the generation. Load in itself does not cause instability but the distance this load is from the generation can have a significant impact on the stability of the units. As the load is moved closer to the actual point of generation, the units become more stable. Thus, increased load in the Wilmington area has a tendency to improve an already adequate situation. No studies have been performed to confirm this because CP&L does not believe they are necessary. With no capacity additions in the area, there is no real driving force to perform these studies. Any change, caused by load growth, would be for the betterment of plant stability. A periodic review of Brunswick stability was conducted during the mid-80s. Results of that study indicated that stability for the Brunswick units was entirely adequate.

The inertial load flow studies referenced in Section 8.2.2 of the FSAR were conducted as another means of demonstrating the security of CP&L's transmission system in general, and especially in the vicinity of the plant. No additional considerations were made in these studies other than the fact that all generating units connected to the interconnection responded in portion to their inertia, a measure of their generating ability and size, to the loss of a Brunswick unit. This is not an extremely severe duty for the system and in fact is often less severe than the duty imposed by replacing this lost generation from a single unit somewhere else on the interconnection. The reason for this is the diversity of the generation that would replace the lost unit. In an inertial study, the replacement capacity comes from many units spread all over the interconnection. Thus, no one facility has to carry a significant amount of replacement power until that power converges on the load centers that were originally served by the Brunswick capacity. The stress is on the CP&L system more so than the neighboring systems. When the lost capacity is replaced from a minimum number of sources, this stress is amplified in the vicinity of the units used for replacement. However, the impact on the CP&L system in the Wilmington area would not be significantly different than that observed in the inertial study. Again, having no need to run inertial studies, additional studies have not been run.

During the normal course of our more traditional planning activities, the Brunswick units are routinely modeled to be shutdown to determine the impact on the transmission loading and voltage profile on the system. This holds for both internal system work as well as interconnections work with neighboring utilities. The standard generation contingency, used to determine transfer capability from neighboring systems, on the CP&L system is the loss of both Brunswick units. This evaluation is performed at least twice annually for each upcoming peak season. Additional future year reliability studies are periodically performed. We have not seen any indication that such a scenario causes overloading problems which could lead to transmission cascading. Even during transmission contingencies, total capacity imports meet or exceed the replacement needs for both Brunswick units without causing a cascading situation to develop.

There appears to be some confusion in trying to tie the inappropriate response of the voltage regulator to the FSAR. CP&L believes that it is inappropriate to correlate the voltage regulator problem with other postulated system stability problems for the following reasons. The voltage swings experienced

were due to the problems internal to the voltage regulator. The regulator drove the unit to a loss of excitation trip. The system was not swinging, nor was the unit swinging in response to actions taking place on the system. The swings were a symptom of the regulator problem, not the cause of the problem. Events on the system called for a certain response from the regulator, but did not cause the regulator to respond as it did.

NRC QUESTION NO. 6

It seems from the event that the plant operator and the power dispatcher were working against each other. The operator was more concerned about maintaining positive MVAR generation (MVAR out) while the dispatcher was more concerned about obtaining a proper system voltage by adding the capacitor banks to raise the grid voltage. These actions resulted not only in raising the grid voltage above its scheduled voltage but also caused MVAR generation into the negative MVAR (MVAR in). In view of the above:

a. Does CP&L have any procedures controlling the grid system voltage? If so, who (the operator or the dispatcher) has the real authority and how is it coordinated between the operator and dispatcher during a normal/emergency situation?

b. What effort, if any, is being developed to prevent this type of operational misunderstanding between the operator and the dispatcher?

CP&L RESPONSE TO QUESTION NO. 6

The power system dispatcher is responsible for maintaining the system grid voltage under normal and emergency conditions. This is accomplished by using the MVAR capability of the generating units on-line and the transmission voltage level capacitor/reactor banks. The power system dispatcher may deviate from the plant voltage schedule to ensure that adequate LOCA voltage support exists.

During the time of this event, the power system dispatcher was not trying to raise the system voltage by switching capacitor banks in service. The dispatcher was switching capacitor banks in service according to a procedure (DTRM-GP-24) written to ensure that adequate MVAR support is available to the area of the Brunswick Plant to support the plant bus voltage in the event of a LOCA. The power system dispatcher also monitors the MVAR generation (using the control system computer's alarming capability) from each Brunswick Unit to determine if the current MVAR generation is equal to or above the minimum requirement. As stated in procedure DTRM-GP-24, the voltage schedule will be maintained unless constrained by MVAR limits. The power system dispatcher and the unit operators stay in close communication (using automatic ring down phone circuits) in order to maintain the plant voltage schedule and required MVAR support. If constrained by MVAR limits, the Unit Operating Procedure prevails. In order to emphasize this position, Standing Instruction 91-029 has been re-issued as Standing Instruction 91-051 and formal training is scheduled for the third quarter 1991.

NRC QUESTION NO. 7

The MVAR generation curve for the Brunswick plant indicates that MVAR generation is designed to move either under or over the excited region based on a given MW generation level and power factor. It is stated in item 1.b of your Standing Instruction 90-090 that for a less than 20 MVARs generation the operator is allowed to raise the generator voltage irrespective of voltage schedule. Provide an explanation regarding the acceptability of such an operator action for less than 20 MVAR generation.

CP&L RESPONSE TO QUESTION No. 7

The 20 MVAR limitation is based on generator stability and is recognized as such by the system dispatcher. Appendix 1, Note 2 of Procedure DTRM-GP-24 allows deviation from the voltage schedule if the Unit is constrained by MVARs.

CP&L has investigated conditions associated with less than 20 MVAR generation and has determined that a 20 MVAR limitation (20 MVARs out) is desirable relative to 230 KV bus voltage and VAR output. During normal generator operation, it is desirable to operate in the overexcited region or with a strong field. During strong field operation, the generator is supplying VARs to the system. Generator operation in the underexcited region, i.e., weak field, is generally termed unacceptable, since the generator would become more susceptible to pulling out of synchronization and voltage regulator stability worsens. CP&L's System Planning and Operations Department has provided guidance for operation relative to 230 KV bus voltage and VAR output to BSEP via memorandum. The memorandum recommends Brunswick Unit Nos. 1 & 2 generators operate with a minimum of 20 MVARs out. The memorandum also recommends close coordination with the load dispatcher to maintain voltage per schedule but, voltage becomes second priority to MVARs and will be allowed to exceed the schedule to maintain the minimum MVAR output.