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NUCLEAR OPERATIONS

October 30, 1980

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Subject: Virgil C. Summer Nuclear Station
Docket No. 50/395
Reactor Systems Branch Questions

Dear Mr. Denton:

In response to your letter dated 10/28/80, South Carolina Electric and Gas Company, acting for itself and agent for South Carolina Public Service Authority provides responses to questions issued by the reactor systems branch as a result of our meeting held in Bethesda on 10/8/80. These will be incorporated in the next FSAR amendment. It should be noted that the response to questions 211.129, 211.131 and 211.132 will be provided at a later date.

If you have any questions, please let us know.

Very truly yours,

T. C. Nichols, Jr.

T. C. Nichols, Jr.

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211.124 Overpressurization of Reactor Vessel at Low Temperature Pressure

For protection of overpressurization of reactor vessel at low temperature and pressure you have provided seismically qualified nitrogen (N_2) supply to each of the PORVs which is sized to assure that no operator action is required to terminate the transient in 10 minutes. Provide justification for this 10 minute limit and why it is enough for the operator to identify and terminate the cause of the transient.

RESPONSE: Two pressurizer power operated relief valves have a seismically qualified supply of Nitrogen to their actuators. In each line there is a 3.6 cubic foot tank where 660 psig nitrogen is stored. A 300 psig alarm (in the control room) is provided to alert the operator of low nitrogen header pressure. A regulator is provided to reduce the pressure to 90 psig to the actuator. The tanks were sized for continuous valve cycling for 10 minutes where 480 cubic inches of nitrogen are used per valve cycle. After this 10 minute period credit may be taken for the control room operator to take action necessary to terminate the overpressurization event. Such actions may be the securing of a charging pump or reactor coolant pump. By manual actuation on the main control board, nitrogen can be re-supplied to the header. There are sufficient indicators available inside the control room for the operator to identify and terminate the event.

211.125 <u>Identification of Indicators and Alarms Provided in the Control Room for Leakage Detection</u>

Provide a table of all indicators and alarms in the control room associated with leak detection instrumentation for all three types of leak detectors.

RESPONSE: The following is a tabulation of leak detection methods inside the control room.

LEAK DETECTION METHODS

INSIDE CONTROL ROOM

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
Boron injector surge tank level	level switch (LS965)	alarm-high level	reactor coolant leakage to ECCS
Refueling water storage tank level	level transmitters (LT990, LT991, LT992, LT993)	indication alarm-high level	reactor coolant leakage to ECCS
accumulator level	level transmitters (LT920, LT922, LT924, LT926, LT928, LT930)	indication alarm-high level	reactor coolant leakage to ECCS
accumulator pressure	pressure transmitters (PT921, PT923, PT925, PT927, PT929, PT931)	indication alarm-high level	reactor coolant leakage to ECCS
reactor vessel flange leak-off temperature	temperature element (TE401)	indication alarm-high temperature	leakage from reactor vessel
pressurizer safety valve discharge temperature	temperature elements (TE463, TE465, TE467, TE469)	indication alarm-high temperature	reactor coolant leakage to pressurizer relief tank
pressurizer relief tank temperature	temperature element (TE471)	indication alarm-high temperature	reactor coolant leakage to pressurizer relief tank
pressurizer relief tank level	level transmitters (LT470)	indication alarm-high level	reactor coolant leakage to pressurizer relief tank
flow in pressurizer relief line	acoustic leak monitor	alarm-high flow	reactor coolant leakage to pressurizer relief tank

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
leak detection drains	level switches	alarm-high level	nuclear valve leak-off and miscellaneous equipment leakage
steam generator blowdown and sampling radiation	radiation monitor (RM-L3, RM-L10)	indication alarm-high radiation	primary to secondary system leakage
main plant vent exhaust radiation	radiation monitor (RM-A3)	indication alarm-high radiation	primary to secondary system leakage
turbine room sump radiation	radiation monitor (RM-L8)	indication alarm-high radiation	primary to secondary system leakage
component cooling water radiation	radiation monitor (RM-L2A, RM-L2B)	indication alarm-high radiation	intersystem leakage into component cooling water system
component cooling water temperature from RHR heat exchanger	temperature elements (TE7037, TW7047) temperature switches (TS7038, TS7048)	indication alarm-high temperature	residual heat removal heat exchanger leakage
component cooling water temperature from reactor coolant drain tank	temperature elements (TE7118)	indication alarm-high temperature	reactor coolant drain tank heat exchanger leakage
component cooling water flow from reactor coolant drain tank	flow transmitters (FT7116)	indication	reactor coolant drain tank heat exchanger leakage
component cooling water temperature from reactor coolant pump thermal barrier	temperature elements (TE7140, TE7160, TE7180)	indication alarm-high temperature	reactor coolant pump thermal barrier leakage
component cooling water flow from reactor coolant pump thermal barrier	flow transmitters (FT7138, FT7158, FT7178)	indication	reactor coolant pump thermal barrier leakage

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
component cooling water temperature from reactor coolant pump bearings	temperature elements (TE7128, TE7134, TE7148, TE7154, TE7168, TE7174)	indication alarm-high temperature	reactor coolant pump bearing leakage
component cooling water flow from reactor coolant pump bearings	flow transmitters (FT7126, FT7132, FT7146, FT7152 FT7166, FT7172)	indication	reactor coolant pump bearing leakage
component cooling water temperature from letdown heat exchanger	temperature element (TE7196)	indication alarm-high temperature	letdown heat exchanger leakage
component cooling water flow from letdown heat exchanger	flow transmitters (FT7194)	indication	letdown heat exchanger leakage
component cooling water temperature from real water heat exchanger	temperature element (TE7188)	indication alarm-high temperature	real water heat exchanger leakage
component cooling water flow from real water heat exchanger	flow transmitter (FT7186)	indication	seal water heat exchanger leakage
component cooling water temperature from RHR pump seal	temperature elements (TE7256, TE7246)	indication alarm-high temperature	RHR pump leakage
component cooling water flow from RHR pump seal	flow transmitters (FT7255, FT7246)	indication	RHR pump leakage
auxiliary building sump level	level switch (LS7742)	alarm-high level	undetected leaks from engineered safety feature systems in the auxiliary building

PARAMETERS	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
auxiliary building ambient temperature	temperature senors	alarm-high temperature	undetected leakage from CVCS letdwon lines or auxiliary steam systems
intermediate building sump level	level switches (LS1950 thru LS1955)	alarm-high level	leakage from feedwater system
RHR pump room sump level	level switches (LS1966, LS1967 LS1968)	alarm-leakage greater than 45 GPM	leakage in RHR pump rooms
reactor building sump level	level transmitters (LT1963, LT1964)	indication alarm-high level and leakage greater than 10 GPM	leakage from systems inside the reactor building
incore instrument sump level	level senor (LS1973, LS1974)	alarm-leakage greater than 1 GPM	leakage around reactor vessel and instrument chase
leak detection sump level	level senor (LS1961, LS1962)	alarm-leakage greater than 1 GPM	leakage from systems inside reactor building
condenser exhaust radiation	radiation monitor (RM-A9)	indication alarm-high radiation	primary to secondary system leakage
reactor building air sample radiation	radiation monitor (RM-A2)	indication alarm-high radiation	reactor coolant leakage
reactor building temperature	temperature elements (TE9201, TE9203)	indication	gross reactor coolant leakage
reactor building pressure	pressure transmitters (PT950, PT951, PT952, PT953	indication	gross reactor coolant leakage

PARAMETERS	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
reactor building cooling unit device flow	flow switches (FS1900A, FS1900B)	alarm-flow greater than 0.5 GPM	reactor coolant leakage

NOTE: For a description of the above leak detection methods and other methods not directly indicated in the control room, see FSAR Section 5.2.7, 7.6.5, 9.3.3, 11.4, 12.2.4 and questions 211.12 and 211.84.

211.126 <u>Loss of CVCS or CCW to Reactor Coolant Pumps or Motors</u>

In response to questions 211.123 concerning loss of CVCS or CCW to reactor coolant pumps you stated that two RCP motors have been tested with interrupted CCW flow, and that the test demonstrates that the RCP motor can withstand loss of CCW flow for 10 minutes without pump damage. Verify that the loss of CCW in both RCP motor bearings and the thermal barrier heat exchangers will not have a worse effect on the RCP than the result of loss CCW to pump motor bearings only as simulated in your test. Also, provide a summary of your pump test.

RESPONSE: The reactor coolant pump can continue to run following a loss of cooling water to the thermal barrier provided that the pump seal temperature remains within allowable temperatures. This will be the case as long as seal injection is maintained. Additionally, since the loss of component cooling water to the reactor coolant pump does not, in itself, affect operation of the pump, a simultaneous loss of cooling water to the thermal barrier and the motor-bearing oil coolers is no worse than a loss of cooling water to the motor bearing oil coolers.

The test run by Westinghouse described in the response to Question 211.123 was applicable to the design used on the Virgil C. Summer Nuclear Station. A description of the test and results are provided in response to Question 211.123 on page 211.123-9.

See the revised response to Question 211.123.

Consequently, the RCP can continue to run following a loss of thermal barrier cooling provided that pump seal temperatures remain within allowable limits. 22

Loss of Component Cooling Water

Should a loss of CCW to the RCPs occur, the chemical and volume control system continues to provide seal injection flow to the RCPs; the seal injection flow is sufficient to prevent damage to the seals with a loss of thermal barrier cooling. However, the loss of CCW to the motor bearing oil coolers will result in an increase in oil temperature and a corresponding rise in motor bearing metal temperature. It has been demonstrated by testing, discussed in part 6, that the reactor coolant pumps will incur no damage as a result of a CCW flow interruption of 10 minutes.

2. Two safety related transmitters are provided to redundantly monitor component cooling water flow to the upper and lower reactor coolant pump bearings. Two additional safety related transmitters are provided to redundantly monitor component cooling water flow to the reactor coolant pump thermal barriers. These transmitters provide flow indication and actuate low flow alarms in the control room. 15

A discussion of th loss of seal injection is provided in item 1, above. This discussion justifies the use of nonsafety grade instrumentation for seal injection flow, since loss of seal injection is not limiting in terms of continued pump operation and does not require immediate operator action.

3. As discussed in part 1, a loss of CCW to the motor bearing oil coolers will result in an increase in oil temperature and a corresponding rise in motor bearing temperature. ~~Westinghouse contends that the loss of CCW to the RCPs will not result in an instantaneous seizure of a single pump and, further, that instantaneous seizure of two pumps simultaneously is not a credible ultimate consequence.~~

Since the loss of CCW to the thermal barrier does not, in itself, affect operation of the RCP, a simultaneous loss of CCW to the thermal barrier and to the motor bearing oil coolers is no worse than a loss of CCW only to the motor bearing oil coolers. 22

AMENDMENT ~~[illegible]~~ 22
~~[illegible]~~, ~~[illegible]~~
November, 1980

The hypothetical seizure of one RCP results in a low flow reactor trip approximately one second after the initiation of the event. As a result of the fast reactor trip and the consequential decrease in core heat flux, the reactor coolant system pressure and the clad temperature reach the peak values at about 2.5 seconds and then start to decrease.

Because the core has been shut down, at 40 seconds-or even 10 seconds - after a pump seizure, the reactor coolant system pressure and the clad temperature transients have decreased to a point at which a second pump seizure results in no noticeable change in the transients.

5. Operating procedures are provided for a loss of component cooling water and seal injection to the reactor coolant pumps and/or 15 motors. Included in these operating procedures is the provision to trip the reactor if component cooling water flow, as indicated by the instrumentation discussed in item 2, above, is lost to the reactor coolant pump motors, and cannot be restored within ten minutes. The reactor coolant pumps will also be tripped following the reactor trip.

This section provides a description of testing performed and the test results which constitute the basis of the reactor coolant pump for 10 minute operation without CCW with no result of damage.

22 6. Two RCP motors have been tested with interrupted CCW flow; these tests were conducted at the Westinghouse Electro Mechanical Division. In both cases, the reactor coolant pumps were operated to achieve "hot" (2230 psia, 552°F) equilibrium conditions. After the bearing temperatures stablized, the cooling water flow to the upper and lower motor bearing oil coolers was terminated and bearing (upper thrust, lower thrust, upper guide and lower guide) temperatures were monitored. A bearing metal temperature of 185°F was established as the maximum test temperature. When that temperature was reached, the cooling water flow was restored.

In both tests, the upper thrust bearing exhibited the limiting temperatures. Figure 211.123-6 shows the upper thrust bearing temperature versus time. In both cases, 185°F was reached in approximately ten minutes.

211.127 Overpressurization of Internal Body Cavity to Gate Valves in the ECCS System

We have been notified of a potential design deficiency regarding double seating gate valves which are used in the ECCS systems of some PWR plants. The concern is that when fluids, trapped in the internal body cavity of the valve, are heated due to the increased temperatures of adjacent piping systems or of the environment, substantial pressure increases may result in these cavities that could rupture the valve. Provide information which addresses this potential valve problem as it applies to the Virgil C. Summer Station.

RESPONSE: The only gate valves of the double disk design used on the Virgil C. Summer Nuclear Station are the three main feedwater containment isolation valves. These valves, however, have incorporated in their design a trapped fluid release feature between the parallel disks to prevent overpressurization of the internal body cavity.

211.128 Credit for Operator Action

Your response to questions 211.108 and 211.120 have only identified three events that require operator manual action to mitigate the consequences of an accident. The response should be expanded to specifically identify the need and the time for operator action for each Chapter 15 event.

RESPONSE: See revised response to question 211.120.

RESPONSE

With exception of the inadvertant boron dilution event which is discussed in section 15.2.4, the response to this question along with the responses to questions 211.59, 211.61, 211.108 and 211.115, address all of those chapter 15 events for which operator action is required to terminate the transient. As can be seen from the discussion which follows, operator action is required before 20 minutes only for the main steam line break.

Lead Paragraph.

Significant events in which a discussion of operator actions in mitigating the consequences of the transient is appropriate are main steam line break, main feed line break, LOCA, and spurious actuation of the ECCS. The significance of operator action for events not mentioned above is addressed in the response to question 211.59 which discusses the standard procedures followed to achieve a normal plant shutdown following an event. The safety issues of concern during the time sequence of operator actions in general is addressed in both the FSAR and in the response to questions 211.59, 211.61, 211.108, and 211.115. 15

The limiting transient is the main steam line break. Operator action ~~is~~ is discussed in the response to questions 211.59 and 211.108. As stated in the response to question 211.108, the time at which operator action is required to limit the cooldown and primary repressurization following a steam line break is in excess of 10 minutes. For the core integrity analysis following either a main steam line break or depressurization of the main steam system, operator action is not required at a specific time to obtain acceptable results. Desirable operator actions and the necessary instrumentation for indication are described for the steam break type event in the response to Q 211.59. 16

In terms of establishing and maintaining long-term control of cooldown, the feedwater line break is less limiting than the steam line break for the following reasons. During the early portion of the feedwater line break, the break effluent consists of water or low quality steam which carries less energy per pound than the dry, saturated steam assumed in the steam line break analysis. Also, since the maximum break size for the feedwater line break is always smaller than for the steam line break, the steam discharge rate must be smaller. Thus, the plant cooldown is less rapid and of a smaller magnitude than for the steam line break. 15

Operator action is required for the following chapter 15 events:

1. Steam line break - greater than 10 minutes, less than 20 minutes,
2. LOCA - greater than 25 minutes.
3. Feedwater line break - greater than 20 minutes.
4. ~~Bor~~ Boron Dilution
   a) refueling - 84 minutes
   b) Cold shutdown - 56 minutes
   c) Power operation - 62 minutes
   d) hot standby - later (See Question 121.131)
   e) startup - later (See Question 121.131)

211.129 <u>Submittal of Revised LOCA Analyses with Corrected Metal-Water Reaction, and Additional Small Break Analyses to Insure Identification of Worst Case Small Break</u>

The licensee has revised the input to his small break LOCA model. This revision resulted from a QA audit which uncovered an input error in modeling the reactor vessel downcomer. The correction reduced the area of the downcomer by a factor of 2. from 52 to 26 ft^2. This input correction resulted in a predicted peak clad temperature decrease of 125°F for the 3-inch break (1833 to 1708°F). The staff is presently evaluating this modification. However, we require that you formally document the corrections made to your small break LOCA model, and revise the analyses presented in the FSAR. In addition, you should discuss why the limiting small break size is not less than 3 inches in diameter (yet greater than 2 inches, which is the size capable of being mitigated by the charging pump alone).

RESPONSE: This information will be provided later.

211.130 **Isolation of Lines Between MISV and Turbine Stop Valves on ESFAS**

Table 10.3-3 of your FSAR indicated that several main steam line valves downstream of MISV's will remain open on ESFAS.

Confirm that the assumed steam release from unaffected steam generators following a main steam break accident as listed in Table 15.4-23 has included the steam released from the open valves identified in Table 10.3-3 and the steam supply to the turbine driven auxiliary feedwater pump.

RESPONSE: The flow given in Table 10.3-3 are the maximum for which the equipment is designed. Flow from the steam traps is dependent on the rate of steam condensation in the main steam lines. The need for pegging steam to maintain deaerator temperature would be greatly reduced as soon as main feedwater flow is stopped.

The procedure that is used to calculate the steam released to the atmosphere from the unaffected steam generators in Chapter 15.4 is based on an energy balance between the reactor coolant system and the steam generators. The calculation consist of calculating the total system energy before the steamline break, adding the energy release (decay heat) over the time span of interest, and subtracting the total system energy at the end to get the amount of heat which must be dissipated by the steam generator safety valves.

After the steam line break the plant is assumed to stabilize at no load conditions within two hours, then cooled down in a six hour time period to where the RHR (Residual Heat Removal System) starts operation (400°F, 600 psia). At this point, atmospheric steam dump is no longer needed to relieve decay heat.

The steam release presented is the total energy dissipated over 8 hours to get the system to RHR temperature and pressure. This includes the decay heat and also a ten percent factor of conservatism.

This steam release presented is independent of the flow paths taken. If we assume all the flow paths available in Table 10.3-3, we would get less energy release to the atmosphere. This is due to the heat capacity of the piping, friction losses, etc. Since we do an energy balance over the RCS and SG, the numbers we present in Table 15.4-23 are clearly limiting.

It should also be noted that credit for operation after 20 minutes can be assumed. If the main steam isolation valve fails to close, the operator could isolate the flow paths identified in Table 10.3-3.

211.131 Analyses of Boron Dilution Events from Hot Standby and Cold Shutdown

a. It is required by the Standard Review Plan that you analyze unplanned boron dilution events. Since the sequences of events that may occur depend on plant conditions at the time of the unplanned moderator dilution, the analyses should include conditions at the time of the unplanned dilution, such as refueling, startup, power operation, hot standby and cold shutdown.

Your Chapter 15 analyses did not include analyses of hot standby and cold shutdown. We request that you include this analyses in your FSAR.

b. What are the assumed causes of an unplanned reactivity insertion during refueling, startup, and at power? What are the necessary actions to be taken by the operator to mitigate each of these events?

Identify the actions to be taken by the operator in the event of the worst single failure postulated in the mitigating system, and show that the time available to the operator to mitigate the event including the effects of the single failure, is sufficient.

RESPONSE: This information will be provided later.

211.132 Containment Sump and its effect on long term cooling following a LOCA

During our reviews of license applications we have identified concerns related to the containment sump design and its effect on long term cooling following a Loss of Coolant Accident (LOCA).

These concerns are related to (1) creation of debris which could potentially block the sump screens and flow passages in the ECCS and the core, (2) inadequate NPSH of the pumps taking suction from the containment sump, (3) air entrainment from streams of water or steam which can cause loss of adequate NPSH, (4) formations of vortices which can cause loss of adequate NPSH, air entrainment and suction of floating debris into the ECCS and (5) inadequate emergency procedures and operator training to enable a correct response to these problems. Preoperational recirculation tests performed by utilities have consistently identified the need for plant modifications.

The NRC has begun a generic program to resolve this issue. However, more immediate actions are required to assure greater reliability of safety system operation. We therefore require you take the following actions to provide additional assurance that long term cooling of the reactor core can be achieved and maintained following a postulated LOCA.

1. Establish a procedure to perform an inspection of the containment, and the containment sump area in particular, to identify any materials which have the potential for becoming debris capable of blocking the containment sump when required for recirculation of coolant water. Typically, these materials consist of: plastic bags, step-off pads, health physics instrumentation, welding equipment scaffolding, metal chips and screws, portable inspection lights, unsecured wood, construction materials and tools as well as other miscellaneous loose equipment. "As licensed" cleanliness should be assured prior to each startup.

   This inspection shall be performed at the end of each shutdown as soon as practical before containment isolation.

2. Institute an inspection program according to the requirements of Regulatory Guide 1.82, item 14. This item addresses inspection of the containment sump components including screens and intake structures.

3. Develop and implement procedures for the operator which addresses both a possible vortexing problem (with consequent pump cavitation) and sump blockage due to debris. These procedures should address all likely scenarios and should list all instrumentation available to the operator (and its location) to aid in detecting problems which may arise, indications the operator should look for, and operator actions to mitigate these problems.

4. Pipe breaks, drain flow and channeling of spray flow released below or impinging on the containment water surface in the area of the sump can cause a variety of problems; for example, air containment, cavitation and vortex formation.

Describe any changes you plan to make to reduce vortical flow in the neighborhood of the sump. Ideally, flow should approach uniformly from all directions.

5. Evaluate the extent to which the containment sump(s) in your plant meet the requirements for each of the items previously identified; namely debris, inadequate NPSH, air entrainment, vortex formation, and operator actions.

The following additional guidance is provided for performing this evaluation.

1. Refer to the recommendations in Regulatory Guide 1.82 (Section C) which may be of assistance in performing this evaluation.

2. Provide a drawing showing the location of the drain sump relative to the containment sumps.

3. Provide the following information with your evaluation of debris:

   a. Provide the size of openings in the fine screens and compare this with the minimum dimensions in the pumps which take suction from the sump (or torus), the minimum dimension in any spray nozzles and in the fuel assemblies in the reactor core or any other line in the recirculation flow path whose size is comparable to or smaller than the sump screen mesh size in order to show that no flow blockage will occur at any point past the screen.

   b. estimate the extent to which debris could block the trash rack or screens (50 percent limit). If a blockage problem is identified, describe the corrective actions you plan to take (replace insulation, enlarge cages, etc.).

   c. For each type of thermal insulation used in the containment, provide the following information:

      i. type of material including composition and density,

      ii. manufacturer and brand name,

      iii. method of attachment,

      iv. location and quantity in containment of each type,

      v. an estimate of the tendency of each type to form particles small enough to pass through the fine screen in the suction lines.

   d. Estimate what the effect of these insulation particles would be on the operability and performance of all pumps used for recirculation cooling. Address effects on pump seals and bearings.

Additionally, previous in-plant sump tests did not accurately replicate expected post-LOCA conditions, and thus did not demonstrate acceptable sump performance under ECCS recirculation conditions. Specifically, the plant test only pulled suction from a single line, when there are two lines in each of two sumps. This resulted in test approach flow velocities which were lower than would be expected during a LOCA.

Additionally, various flow approach directions were not investigated to determine if undesirable rotation could be induced in the sump area, which could lead to vortex formation.

Finally, sump screen blockage due to debris entrainment was not considered, with the correspondingly higher screen velocities which also could aggrevate vortex formation.

The applicability of your sump tests, and the adequacy of your sump design under post-LOCA conditions, in light of these staff concerns should be addressed to provide assurance that recirculation sump performance will be acceptabl following a postulated LOCA, and that undesirable vortex formation will not be experienced.

RESPONSE: This information will be provided later.