October 17, 2001

Mr. David A. Christian
Senior Vice President and
Chief Nuclear Officer
Virginia Electric and Power Company
Innsbrook Technical Center - 2SW
5000 Dominion Blvd
Glen Allen, VA 23060-6711

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION RELATED TO THE STAFF'S REVIEW OF SEVERE ACCIDENT MITIGATION ALTERNATIVES FOR THE SURRY AND NORTH ANNA POWER STATIONS, UNITS 1 AND 2 (TAC NOS. MB1992, MB1993, MB1994, AND MB1995)

Dear Mr. Christian:

The NRC staff has reviewed Virginia Electric and Power Company's analysis of severe accident mitigation alternatives, submitted as part of the application for license renewal for the Surry and North Anna Power Stations, Units 1 and 2. As discussed with your staff in a telephone call on August 30, 2001, the staff has identified areas where additional information is needed to complete its review. Enclosed are the staff's requests for additional information (RAIs).

As discussed with your staff, we request that you provide your responses to these RAIs by December 14, 2001, in order to support an accelerated review schedule. If you have any questions, please contact me at (301) 415-2828.

Sincerely,
/s/AJKugler
Andrew J. Kugler, Senior Project Manager
Risk Informed Initiatives, Environmental,
Decommissioning, and Rulemaking Branch
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation.

Docket Nos. 50-280, 50-281, 50-338, and 50-339

Enclosure: As stated

cc w/encl: See next page

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Dear Mr. Christian:

The NRC staff has reviewed Virginia Electric and Power Company's analysis of severe accident mitigation alternatives, submitted as part of the application for license renewal for the Surry and North Anna Power Stations, Units 1 and 2. As discussed with your staff in a telephone call on August 30, 2001, the staff has identified areas where additional information is needed to complete its review. Enclosed are the staff's requests for additional information (RAIs).

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OFFICE	PM:RGEB	SC:RGEB	C:RGEB	C:RLSB
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OFFICE OF NUCLEAR REACTOR REGULATION
REQUEST FOR ADDITIONAL INFORMATION
RELATED TO THE STAFF'S REVIEW OF
SEVERE ACCIDENT MITIGATION ALTERNATIVES RELATED TO
LICENSE RENEWAL FOR NORTH ANNA POWER STATION, UNITS 1 AND 2,
AND SURRY POWER STATION, UNITS 1 AND 2
(TAC NOS. MB1992, MB1993, MB1994, AND MB1995)

Questions Related to Surry Power Station (SPS)

1. The license renewal SAMA analysis is based on an internal events core damage frequency (CDF) of 3.8 x 10^{-5} per reactor-year, which is about 50 percent of the value reported in the Individual Plant Evaluation (IPE, i.e., 7.4 x 10^{-5} per reactor-year). Also, you indicate on page G-18 of the submittal that the level 2 Probabilistic Risk Assessment (PRA) for SPS was updated for the purpose of the Severe Accident Mitigation Alternatives (SAMA) evaluation. In this regard please provide the following:

   a. a discussion of the reasons for the reduction in CDF, including a description of the major changes in PRA models/assumptions and plant hardware/procedures, and their respective impacts on CDF,

   b. a breakdown of the internal events CDF (3.8 x 10^{-5} per reactor-year) by initiating event, specifically, Transients, Loss-of-coolant accident (LOCA), Steam generator tube rupture (SGTR), and Interfacing system LOCA (ISLOCA),

   c. a description of the changes to the level 2 analysis and their impact on results,

   d. the updated conditional probabilities associated with each release category for each plant damage state (PDS) (i.e., the Containment Matrix), the list of updated plant damage state definitions if different from IPE, and the updated PDS frequencies and release class frequencies, and

   e. a description of the internal and external peer reviews of the PRA used in the SAMA analysis.

2. As indicated on page 4-45, the top 100 cutsets of the updated level 1 PRA were examined for the SAMA analysis:

   a. Please indicate the total fractional contribution to CDF and risk that result from these 100 top cutsets,

   b. Please confirm whether an importance analysis was performed, and if so, did such analysis identify any additional SAMAs, and

   c. If an importance analysis was not performed, then please justify its exclusion basis, considering that importance ranking of initiators has the potential to identify possible actions that would not appear in a listing of top cutsets.

ENCLOSURE

3. To account for the risk impact of internal fires and external events, you multiplied the internal events IPE CDF by 2, except for the contributions due to bypass events (i.e., ISLOCA and SGTR), on the grounds that external events would not impact the frequency of bypass scenarios. Risk analyses at other commercial nuclear power plants indicate that external events could be large contributors to core damage and the overall risk to the public. Even though the submittal indicates that the contributions of external events are not significant, the quantitative influence of SAMAs applicable to internal fires/floods and external events cannot be accurately evaluated by just doubling the estimated internal events CDF for selected sequences. In view of the fact that the characteristics of the internal and external events scenarios are, in general, considerably different and include different levels of uncertainties and conservatism, please provide the following:

   a. further discussion of the uncertainties associated with the calculated CDF for internal events (including internal flooding) for SPS, (e.g., the mean and median CDF estimates and the 5th and 95th percentile values of the uncertainty distribution) and the rationale for not explicitly considering the upper end of the uncertainty distribution in the SAMA evaluation process.

   b. justification that by doubling the internal events CDF, one can reliably bound the risk of core damage due to all initiators at SPS, including the impact of uncertainties in PRA results. This justification should be based on plant-specific considerations and sound PRA arguments, and

   c. the technical rationale for including only a very limited number of SAMA candidates directed towards mitigation of external events.

4. On page G-9 you state that the base case does not include sheltering as part of the emergency planning assumptions in the MELCOR Accident Consequence Code System (MACCS) calculations. On the other hand, on page G-28 you state that "(a)nother sensitivity run was made for the time to take shelter (MACCS parameter DLTSHL) which used 7200 seconds, whereas the base case used 5400 seconds." Please explain this discrepancy. **During the telephone call between the staff and the licensee on August 30, 2001, the licensee clarified what is presented in the Environmental Report (i.e., that the duration used for sheltering was 0 and the time to take shelter was 7200). The staff concluded that there was no discrepancy in the Environmental Report and that no response to this question is necessary.**

5. In Table G.2-2 for SAMAs 35 and 36 (containment venting to remove decay heat), the calculated CDF is reduced by about 4.9 percent. Please explain the process by which the proposed vent is envisioned to remove the core-generated decay heat, thereby preventing core damage.

6. Please provide the basis for the low release fractions (i.e., lower than a near complete release to environment) for noble gases for source term categories (STCs) 2, 5, and 21. In addition, please explain the zero release fractions for Tellurium (STCs 2 and 21), Strontium (STCs 2 and 13), Rubidium (STC 13), Lanthanum (STCs 2, 11, 13, 15, and 21), and Cesium (STCs 11, 13, 15, 18, 21, and 22).

7. Please respond to the following questions related to calculated cost, benefit, and screening criteria for specific SAMAs and SAMA candidates:

   a. SAMA 21 (procedural enhancements for loss of component cooling water or service water) is listed as having negligible benefit (for the option without a completely new, independent pump) because it is able to delay, but not prevent, system failure. It is not clear why delaying system failure (and presumably delaying core damage) has zero risk benefit. Please provide specific results from the risk analysis to show that this benefit is negligible. **During the telephone call between the staff and the licensee on August 30, 2001, the licensee pointed out the explanation related to SAMA 21 on page G-56 of the Environmental Report. After further reviewing the basis for the licensee's conclusion in the Environmental Report, the staff concluded that the explanation was sufficient and that no response to this question is necessary.**

   b. SAMAs 43 and 44 (reactor cavity flooding) may be expected to impact environmental release due to impacts on both ex-vessel coolability and decontamination of ex-vessel release. Please provide specific results from the risk analysis that support assigning no risk benefit to these actions.

   c. SAMA 70 (emphasizing steps in recovery of offsite power after a station blackout [SBO]) is estimated to have a bounding benefit of $33K. Since this SAMA could be implemented as a procedural change, it is not clear that the cost would exceed twice the benefit. Please provide and justify the cost estimate for implementation of this SAMA. Furthermore, please discuss whether any existing procedures for coping with SBOs already address SAMA 70.

   d. SAMA candidate 95 (enhancing inspection activities to prevent ISLOCAs) is screened out by stating that it is not feasible to institute a 100 percent effective and complete inspection program, and that even if it were possible, such a program would extend plant outage durations and thus make the cost excessive. Given the fact that the potential benefit for eliminating ISLOCAs is substantial (about $253K), please explain why less complete or less costly measures were not considered for potential cost-benefit (e.g., rotating partial inspections during outages, or installing radiation or level alarms at strategic locations).

   e. SAMA candidate 141 (enlarging the refueling water storage tank [RWST]) was apparently identified from examination of the top cutsets in the SPS PRA. However, it is screened out by stating that this change has already been implemented. Please state whether the PRA that was used takes credit for the change, and, if not, provide justification for why even further enlargement was not considered past the preliminary screening phase (since it would then still have non-zero benefit).

   f. Given that the submittal indicates that SAMA candidate 151 (creation of a boron injection system [BIS]) has already been implemented, please explain why SAMA candidate 148 (creation of an alternate or backup BIS) can be screened out as "not applicable".

g. SAMA candidate 102 (installing limit valves to prevent containment isolation failure) is the only SAMA candidate dealing directly with failure to isolate the containment. Please explain why other methods for coping with containment isolation failure (e.g., procedural changes aimed at increasing isolation recovery probability before core damage) are not worth consideration. Also, please provide the frequency of core damage events at SPS accompanied by failure to isolate containment, and a bounding value for the realizable risk benefit due to such events.

h. No SAMA candidate was evaluated that would involve the refill of an affected steam generator following an un-isolated SGTR event. Refill of a damaged steam generator is typically a part of severe accident management guidelines and could be accomplished using alternative water sources (e.g., fire water). Please provide justifications for not considering this seemingly beneficial and low-cost SAMA. **During the telephone call between the staff and the licensee on August 30, 2001, the licensee pointed out that this issue is covered by SAMA number 91 in the Environmental Report. The staff concluded that there was no discrepancy in the Environmental Report and that no response to this question is necessary.**

i. What is the basis for the estimated cost of SAMA 47 (Core Melt Source Reduction System [COMSORS]) that would cause it to exceed twice the bounding benefit of $1.6 million?

8. Please clarify the benefit and estimated cost values reported in Table 4-6, and how they were obtained. Specifically:

a. It is the staff's understanding that the "Benefit" values reflect a doubling to account for external events, and that the "Estimated Cost" values also reflect a doubling (the "2 x" in the equation, "2 x benefit") to account for cost uncertainty (page 4-48). Is this correct?

b. On page 4-70, for SAMA 47, the benefit is given as $1.6 million. We assumed that this was determined by multiplying 100 percent times the maximum benefit that can be obtained by mitigating the consequences of a core damage accident, namely $1.6 million. If this is the case, there appears to be an inconsistency in the value for SAMA 42 (page 4-69), a similar SAMA in the sense that the reduction in CDF is zero, for which the bounding benefit is estimated to be $45K. The corresponding Reduction in Person-Rem Offsite is 4.9 percent. According to our calculation (4.9% times $1.6 million), the bounding benefit should be $78K, not $45K. Please explain this apparent discrepancy.

Questions Related to North Anna Power Station (NAPS)

1. The license renewal SAMA analysis is based on an internal events CDF of 3.5×10^{-5} per reactor-year, which is about 50 percent of the value reported in the IPE (i.e., 6.8×10^{-5} per reactor-year). Also, on page G-18 of the submittal, it is stated that the level 2 PRA for NAPS was updated for the purpose of the SAMA evaluation. In this regard please provide the following:

a. a discussion of the reasons for the reduction in CDF, including a description of the major changes in PRA models/assumptions and plant hardware/procedures, and their respective impacts on CDF,

b. a breakdown of the internal event CDF (3.5×10^{-5} per reactor-year) by initiating event, specifically, Transients, LOCA, SGTR, and ISLOCA,

c. a description of the changes to the level 2 analysis and their impact on results,

d. the updated conditional probabilities associated with each release category for each PDS (i.e., the Containment Matrix), the list of updated plant damage state definitions if different from IPE, and the updated PDS frequencies and release class frequencies, and

e. a description of the internal and external peer reviews of the PRA used in the SAMA analysis.

2. As indicated on page 4-45, the top 100 cutsets of the updated level 1 PRA were examined for the SAMA analysis:

   a. Please indicate the total fractional contribution to CDF and risk that result from these 100 top cutsets,

   b. Please confirm whether an importance analysis was performed, and if so, did such analysis identify any additional SAMAs, and

   c. If an importance analysis was not performed, then please justify its exclusion basis, considering that importance ranking of initiators has the potential to identify possible actions that would not appear in a listing of top cutsets. Note that, in your discussion of Level 1 PRA results in the North Anna IPE, you provide both a list of top cutsets (Table 3.4.1-3) and F-V, RRW, and RAW importance ranking (Table 3.4.1-6), as well as several pages of discussion (on pages 3-116 through 3-119) on the most significant events for risk reduction based on this importance ranking.

3. To account for the risk impact of internal fires and external events, you multiplied the internal events IPE CDF by 2, except for the contributions due to bypass events (i.e., ISLOCA and SGTR), on the grounds that external events would not impact the frequency of bypass scenarios. Risk analyses at other commercial nuclear power plants indicate that external events could be large contributors to core damage and the overall risk to the public. Even though the submittal indicates that the contributions of external events are not significant, the quantitative influence of SAMAs applicable to internal fires/floods and external events cannot be accurately evaluated by just doubling the estimated internal events CDF for selected sequences. In view of the fact that the characteristics of the internal and external events scenarios are, in general, considerably different and include different levels of uncertainties and conservatism, please provide the following:

a. further discussion of the uncertainties associated with the calculated CDF for internal events (including internal flooding) for NAPS, (e.g., the mean and median CDF estimates and the 5th and 95th percentile values of the uncertainty distribution) and the rationale for not explicitly considering the upper end of the uncertainty distribution in the SAMA evaluation process.

b. justification that by doubling the internal events CDF, one can reliably bound the risk of core damage due to all initiators at NAPS, including the impact of uncertainties in PRA results. This justification should be based on plant-specific considerations and sound PRA arguments, and

c. the technical rationale for including only a very limited number of SAMA candidates directed towards mitigation of external events.

4. On page G-9 you state that the base case does not include sheltering as part of the emergency planning assumptions in MACCS calculations. On the other hand, on page G-28 you state that "(a)nother sensitivity run was made for the time to take shelter (MACCS parameter DLTSHL) which used 7200 seconds, whereas the base case used 5400 seconds." Please explain this discrepancy. **During the telephone call between the staff and the licensee on August 30, 2001, the licensee clarified what is presented in the Environmental Report (i.e., that the duration used for sheltering was 0 and the time to take shelter was 7200). The staff concluded that there was no discrepancy in the Environmental Report and that no response to this question is necessary.**

5. In Table G.2-2 for SAMAs 35 and 36 (containment venting to remove decay heat), the calculated CDF is reduced by about 0.7 percent. Please explain the process by which the proposed vent is envisioned to remove the core generated decay heat, thereby preventing core damage.

6. Please provide the basis for the low release fractions (i.e., lower than a near complete release to environment) for noble gases for source term categories (STCs) 2, 5, and 21. In addition, please explain the zero release fractions for Tellurium (STCs 2 and 21), Strontium (STCs 2 and 13), Rubidium (STC 13), Lanthanum (STCs 2, 11, 13, 15, and 21), and Cesium (STCs 11, 13, 15, 18, 21, and 22).

7. Please respond to the following questions related to calculated cost, benefit, and screening criteria for specific SAMAs and SAMA candidates:

a. SAMA 21 (procedural enhancements for loss of component cooling water or service water) is listed as having negligible benefit ($0) because it is able to delay, but not prevent, system failure. It is not clear why delaying system failure (and presumably delaying core damage) has zero risk benefit. Please provide specific results from the risk analysis to show that this benefit is negligible. **During the telephone call between the staff and the licensee on August 30, 2001, the licensee pointed out the explanation related to SAMA 21 on page G-56 of the Surry Power Station Environmental Report. The same basis would apply to North Anna Power Station. After further reviewing the basis for the licensee's conclusion in the**

Environmental Report, the staff concluded that the explanation was sufficient and that no response to this question is necessary.

b. SAMAs 43 and 44 (reactor cavity flooding) may be expected to impact environmental release due to impacts on both ex-vessel coolability and decontamination of ex-vessel release. Please provide specific results from the risk analysis that support assigning no risk benefit to these actions.

c. In SAMA 60, the estimated benefit for providing longer battery capability is stated to be $876K, while in SAMAs 61 and 64, the maximum benefit for extending battery power is given as $29K. In addition, from screened SAMA candidate 66, increasing battery reliability apparently has negligible risk benefit, so the above stated benefits are presumably due only to extended battery operating time. Please explain the reason for this apparent discrepancy in benefit for extending battery operating time.

d. SAMA 70 (emphasizing steps in recovery of offsite power after a SBO) is estimated to have a bounding benefit of $72K. Since this SAMA could be implemented as a procedural change, it is not clear that the cost would exceed twice the benefit. Please provide and justify the cost estimate for implementation of this SAMA. Furthermore, please discuss whether any existing procedures for coping with SBOs already address SAMA 70.

e. SAMA candidate 93 (enhancing inspection activities to prevent ISLOCAs) is screened out by stating that it is not feasible to institute a 100 percent effective and complete inspection program, and that even if it were possible, such a program would extend plant outage durations and thus make the cost excessive. Given the fact that the potential benefit for eliminating ISLOCAs is substantial (about $220K), please explain why less complete or less costly measures were not considered for potential cost-benefit (e.g., rotating partial inspections during outages, or installing radiation or level alarms at strategic locations).

f. SAMA candidate 139 (enlarging the RWST) was apparently identified from examination of the top cutsets in the NAPS PRA. However, it is screened out by stating that this change has already been implemented. Please state whether the PRA that was used takes credit for the change, and, if not, provide justification for why even further enlargement was not considered past the preliminary screening phase (since it would then still have non-zero benefit).

g. Given that the submittal indicates that SAMA candidate 149 (creation of a BIS) has already been implemented, please explain why SAMA candidate 146 (creation of an alternate or backup BIS) can be screened out as “not applicable”.

h. SAMA candidate 100 (installing limit valves to prevent containment isolation failure) is the only SAMA candidate dealing directly with failure to isolate the containment. Please explain why other methods for coping with containment isolation failure (e.g., procedural changes aimed at increasing isolation recovery probability before core damage) are not worth consideration. Also, please provide the frequency of core

damage events at NAPS accompanied by failure to isolate containment, and a bounding value for the realizable risk benefit due to such events.

i. No SAMA candidate was evaluated that would involve the refill of an affected steam generator following an un-isolated SGTR event. Refill of a damaged steam generator is typically a part of severe accident management guidelines and could be accomplished using alternative water sources (e.g., fire water). Please provide justifications for not considering this seemingly beneficial and low-cost SAMA. **During the telephone call between the staff and the licensee on August 30, 2001, the licensee pointed out that this issue is covered by SAMA number 89 in the Environmental Report. The staff concluded that there was no discrepancy in the Environmental Report and that no response to this question is necessary.**

j. What is the basis for estimated cost of SAMA 47 (Core Melt Source Reduction System [COMSORS]) that would cause it to exceed twice the bounding benefit of $2.2 million?

8. Please clarify the benefit and estimated cost values reported in Table 4-6, and how they were obtained. Specifically:

   a. It is the staff's understanding that the "Benefit" values reflect a doubling to account for external events, and that the "Estimated Cost" values also reflect a doubling (the "2 x" in the equation, "2 x benefit") to account for cost uncertainty (page 4-48). Is this correct?

   b. On page 4-71 for SAMA 38 the benefit is given as $2K. We assumed that this was determined by multiplying 0.1 percent times the maximum benefit that can occur for mitigating the consequences of a core damage accident, namely $2.2 million, and rounding to the nearest thousand. If this is the case, there appears to be an inconsistency in the value for SAMA 42, a similar SAMA in the sense that the reduction in CDF is zero, where the bounding benefit is estimated to be $14K. The corresponding Reduction in Person-Rem Offsite is 1.1 percent. According to our calculation (1.1% times $2.2 million), the bounding benefit should be $24K, not $14K. Please explain this apparent discrepancy.

9. The gross electrical rating of NAPS is greater than the generic plant rating of 910 MWe. As a result, on page 4-44, you indicated that a scaling factor of 1.08 would be applied to the applicable formula. It is not apparent that this was done. Please confirm whether the indicated scaling factor was used.

cc:

Mr. David R. Lewis, Esquire
Shaw Pittman
2300 N Street, NW
Washington, DC 20037

Mr. Richard H. Blount, II
Site Vice President
Surry Power Station
Virginia Electric and Power Company
5570 Hog Island Road
Surry, Virginia 23883

Dr. W. T. Lough
Virginia State Corporation
Commission
Division of Energy Regulation
P.O. Box 1197
Richmond, Virginia 23209

Robert B. Stroube, M.D., M.P.H.
Acting Deputy State Health Commissioner
Office of the Commissioner
Virginia Department of Health
Room 214
P. O. Box 2448
Richmond, Virginia 23218

Old Dominion Electric Cooperative
4201 Dominion Blvd.
Glen Allen, Virginia 23060

Mr. Stephen P. Sarver, Director
Nuclear Licensing & Operations Support
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Blvd.
Glen Allen, Virginia 23060-6711

Office of the Attorney General
Commonwealth of Virginia
900 East Main Street
Richmond, Virginia 23219

Mr. William Corbin
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glenn Allen, Virginia 23060-6711

Mr. Alan Nelson
Nuclear Energy Institute
1776 I Street NW
Suite 400
Washington, D.C. 20006

Senior Resident Inspector
Surry Power Station
U.S. Nuclear Regulatory Commission
5850 Hog Island Road
Surry, Virginia 23883

Chairman
Board of Supervisors of Surry County
Surry County Courthouse
Surry, Virginia 23683

Mr. Alan Zoellner
Government Information Department
Swem Library
College of William and Mary
P.O. Box 8794
Williamsburg, VA 23187-8794

Caudle A. Julian
U.S. NRC, Region II
Sam Nunn Atlanta Federal Center, 23 T85
61 Forsyth Street, S.W.
Atlanta, Georgia 30303-3415

Ms. Lillian Cuoco
Dominion Nuclear Connecticut, Inc.
Millstone Power Station
Rope Ferry Road
Building 475/5
Waterford, Connecticut 06385