VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

July 9, 1998

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D. C. 20555

Serial No.	98-300
NL&OS/SLW	R1
Docket Nos.	50-280
	50-281
License Nos.	DPR-32
	DPR-37

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
RESPONSE TO SURRY PLANT DESIGN INSPECTION
NRC INSPECTION REPORT NOS. 50-280/98-201 AND 50-281/98-201

We have reviewed Inspection Report No. 50-280/98-201 and 50-281/98-201 dated May 11, 1998 for Surry Units 1 and 2. This report documents the NRC's plant design inspection conducted February 16, 1998 through March 27, 1998. As requested in the Inspection Report, we have developed a schedule and corrective action plan for the unresolved and inspector follow-up items identified in Appendix A of the report. Immediate corrective actions have been taken for items of potential safety significance and action plans for aggressive resolution of the remaining open items have been developed. The specific schedule and corrective action plan for each item is provided in Attachment 1.

The Inspection Report also noted items of a programmatic concern. The corrective actions taken to date and the plan to resolve these corrective action, configuration management and engineering calculation process issues are provided in Attachment 2. This plan includes provisions to 1) conduct a root cause evaluation of uncompleted corrective action resulting from the internal Electrical Distribution System Functional Assessment, 2) evaluate the applicability of the Inspection Report's results and findings to other plant systems and components, and 3) assess their impact on our earlier response to the NRC's 10 CFR50.54(f) request for information dated October 9, 1996. A summary of the commitments made to resolve issues identified in the Inspection Report is provided in Attachment 3.

Additionally, we are addressing discrepancies and weaknesses identified in the Inspection Report, but not included in the cover letter or Appendix A. These items have been assigned to responsible individuals for resolution, action plans are being developed and the items are being tracked in our corrective action program.

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We have no objection to this letter being made part of the public record. Please contact us if you have any questions or require additional information.

Very truly yours,

James P. O'Hanlon
Senior Vice President - Nuclear

Attachments

cc: US Nuclear Regulatory Commission
Region II
Atlanta Federal Center
61 Forsyth Street, S.W., Suite 23T85
Atlanta, Georgia 30303

Mr. R. A. Musser
NRC Senior Resident Inspector
Surry Power Station

ATTACHMENT 1

CORRECTIVE ACTION PLANS FOR UNRESOLVED ITEMS AND INSPECTOR FOLLOW-UP ITEMS

ITEM NUMBER 50-280/98-201-01

FINDING TYPE IFI

DESCRIPTION LHSI Pump NPSH (Section E1.2.1.2(d))

NRC ISSUE DISCUSSION

"The most limiting case for the NPSH available to the LHSI pumps was determined to be at the time of switchover to cold leg recirculation from the containment sump. The most limiting accident scenario was the double-ended pump suction guillotine (DEPSG) break with minimum safeguards and maximum SI single train flow. These calculations determined that the available NPSH of 16.7 ft at the time of switchover to recirculation phase exceeded the required NPSH of 15.8 ft (.9 ft NPSH margin). To justify the available NPSH of 16.7 ft, a containment overpressure of 12 ft and a containment water height of 4.2 ft was credited.

The team noted that the use of containment overpressure, which is the difference of containment pressure and sump vapor pressure, has generally not been encouraged by the NRC as indicated in Regulatory Guide 1.1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps" and NUREG 800, "Standard Review Plan," Section 6.2.2. However, in the various correspondences held between the NRC and Virginia Electric & Power Company (VEPCo) during the period from 1977 to 1978, the team found that VEPCo had always credited the use of containment overpressure in determining the available NPSH for the LHSI pump.

Based on the small amount of NPSH margin available to the LHSI pumps, and because there is a potential negative impact on pump NPSH from containment sump screen blockage, which is discussed in the RS system review (Section E1.3.1.2(c)), the team identified the determination of available NPSH to the LHSI pump as an Inspection Followup Item 50-280/98-201-01."

VIRGINIA POWER RESPONSE

The existing analysis results for Low Head Safety Injection (LHSI) pump available Net Positive Suction Head (NPSH) demonstrate that conditions are sufficient for the pumps to perform their safety-related function. This determination is based upon conservative analyses of the large break loss of coolant accident (LOCA) design basis accident scenario which establishes the most demanding conditions for core and containment heat removal from the LHSI pumps. The limiting scenario has been established by prior analysis sensitivity studies as a double-ended guillotine break in the pump suction piping. The analysis of NPSH for the LHSI pumps employs conservatisms of the following type:

- Scenario development
  - Break flow model, break size and location
  - Loss of offsite power
  - Limiting single active failure

- Key modeling assumptions
  - Core decay heat is calculated using ANS Standard ANSI/ANS-5 1979 plus 2 sigma uncertainty
  - Use of pressure flash break effluent model, which assumes fluid expands at constant enthalpy to the containment total pressure. Saturated vapor goes to atmosphere; saturated liquid goes to sump (unmixed with atmosphere)

- Limiting values of key analysis parameters
  - Maximum Containment Spray (CS), Inside Recirculation Spray (IRS) and Outside Recirculation Spray (ORS) spray thermal efficiency
  - Minimum Refueling Water Storage Tank (RWST) Water Volume
  - Maximum RWST Level Setpoint for Recirculation Mode Transfer (RMT)
  - Maximum RWST Temperature
  - Minimum Service Water (Service Water) Flowrate
  - Maximum Service Water Temperature
  - Maximum Containment Bulk Average Temperature
  - Minimum Containment Initial Air Partial Pressure
  - Minimum IRS and ORS Flowrate (assumed for heat removal)
  - Maximum LHSI flowrate for establishing required NPSH
  - Minimum CS Flowrate

The existing recirculation spray and LHSI pump NPSH analysis for Surry takes credit for containment pressure during the design basis LOCA to provide a part of the available NPSH. The calculation method uses the modeling and parameter assumptions listed above to obtain a conservative prediction of containment pressure (underestimated) and the sump water temperature (overestimated) transients. The containment response analysis minimizes the energy release to the containment atmosphere and maximizes the energy release to the sump water. This is accomplished by employing conservative modeling (pressure flash model) of the break mass and energy releases in the LOCTIC containment response computer code. Virginia Power summarized the analysis results and approach concerning use of containment overpressure in the response to Generic Letter 97-04 (Reference 1). Reference 1 indicated that this approach is consistent with existing regulatory guidance for plants with subatmospheric containments, as described in NUREG-0800, Section 6.2.2.

The existing analysis approach, which credits a conservative transient analysis for containment overpressure, was first employed during 1977, following notification from SWEC of inadequacies in the analysis and system design of the recirculation spray and low head safety injection subsystems. There were numerous letters between VEPCO and NRC during 1977 and 1978 addressing the analyses and proposed modifications to

resolve the NPSH issue for Surry. The NPSH analysis methodology was the subject of a March 2, 1998 meeting with several of the NRC inspectors during the recent Surry A/E inspection. Several key letters relating to licensing of this approach for Surry were provided to the inspectors following this meeting and are summarized in Table 1. This correspondence indicates that NRC staff was aware of Virginia Power's methodology to credit containment overpressure and found these methods and calculation results acceptable for Surry.

The NPSH analysis results reported in Reference 1 are among the analyses submitted with the Surry core power uprating request (Reference 2) and are currently reflected in Tables 6.2-12 and 6.2-13 of the Surry UFSAR for the safety injection and recirculation spray pumps, respectively. During the fall of 1997, an assessment was performed for changes which involved removal of concrete heat sinks and relaxation of the recalibration/recertification schedules for certain containment RTDs used in monitoring key parameter initial conditions. These changes modified the reported NPSH results from the previously submitted uprating analysis. This assessment, which represents a sensitivity and supplements the prior analysis, was implemented under the provisions of 10CFR50.59. The UFSAR updates, which reflect the revised results, have been approved by the Station Nuclear Safety and Operating Committee (SNSOC) and are being incorporated into the UFSAR.

COMPLETION SCHEDULE

No further action is needed with regard to the issue of crediting a conservatively derived containment overpressure for pump NPSH analysis.

With regard to the impact on pump NPSH from sump screen blockage, Virginia Power has included evaluation of the effects of sump screen blockage on LHSI and RS pump suction head losses in the actions identified to address item IFI-98-201-20 (Unqualified Coatings).

REFERENCES

1. Letter from James P. O'Hanlon to USNRC, "Virginia Electric and Power Company-Surry Power Station Units 1 and 2, North Anna Power Station Units 1 and 2-Response to NRC Generic Letter 97-04, Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal," Serial No. 97-594A, 12/29/97.

2. Letter from James P. O'Hanlon to USNRC, "Virginia Electric and Power Company-Surry Power Station Units 1 and 2-Proposed Technical Specifications Changes to Accommodate Core Uprating," Serial No. 94-509, 8/30/94.

Table 1

Licensing Correspondence Concerning NPSH Analysis Methods & Overpressure Credit

Item	Document Description	Purpose
1	Section 6.2.2 of the Standard Review Plan.	N/A.
2	VEPCO 10-15-70 and 3-15-71 response to AEC question 6.11	This response provides the formula used for calculating the NPSHa and specifically states that credit is taken for pressurization of the containment.
3	VEPCO 8/20/77 submittal (Serial No. 362) justifying continued operation with less than the desired NPSH to the recirculation spray pumps.	This submittal provides documentation from the pump manufacturer to indicate that the pumps will continue to operate to a minimum NPSH of 7 feet.
4	NRC 8/20/77 Safety Evaluation for the NPSH problem at Surry.	Documents NRC awareness of the identified problem with the NPSHa as a result of new considerations in the overall thermodynamic model. In this SE, the NRC specifically acknowledges that, "The calculated pressure of the containment and the temperature of the water that accumulates in the containment sump are important parameters in determining recirculation cooling pump operability following a LOCA with regard to available NPSH. These terms in combination with the pump static head and associated line losses establish available NPSH during the transient."
5	VEPCO 8/24/77 submittal (Serial No. 366) transmitting the detailed report of tests and analyses for the NPSH issue.	Documents that adequate NPSH would be available for the IRS pumps but not the ORS pumps during a LOCA. (Adequate safety is assured by the inside pumps). Commits to installing flow-limiting orifices in the discharge of the outside recirculation spray pumps.
6	NRC Order for Modification of License dated 8/24/77.	Requested additional analysis from VEPCO on the NPSH issue. Also, the NRC again specifically acknowledged that, "The calculated pressure of the containment and the temperature of the water that accumulates in the containment sump are important parameters in determining recirculation cooling pump operability following a

		LOCA with regard to available NPSH. These terms in combination with the pump static head and associated line losses establish available NPSH during the transient."
7	VEPCO 9/12/77 submittal (Serial No. 382/082477) providing the analyses requested in the NRC order of 8/24/77.	This submittal provides the requested curves showing the response of containment total pressure, containment vapor pressure, available NPSH, sump water level, and sump water vapor pressure.
8	NRC Order for Modification of License dated 10/17/77.	The NRC specifically states that for the analyses submitted on 9/12/77, "The methods used to calculate the containment pressure, containment sump temperature, and available NPSH have been reviewed for the North Anna plant and found to be acceptable. The same methods were used in calculations for Surry."

ITEM NUMBER 50-280/98-201-02

FINDING TYPE IFI

DESCRIPTION Error in Calculation SM-1047, "Reactor Cavity Water Holdup" (Section E1.2.1.2(d))

NRC ISSUE DISCUSSION

"Calculation SM-1047, "Reactor Cavity Water Holdup," Revision 1 failed to account for some of the water volume lost over a period of time from the containment floor. This error resulted in derivation of containment water height which was greater than that would actually occur during an accident. SM-1047 identified the various sources which added water to the containment and the paths which drained water from the containment floor. The team's purpose of reviewing SM-1047 was to verify that the containment flood height values used in calculation 01039.6210-US-(B)-107, "Containment LOCA Analysis for Core Uprate," Revision 0 was conservative. Calculation 01039.6210-US-(B)-107 was used to determine the NPSH requirements for the IRS, ORS and LHSI pumps.

The team found that SM-1047 did not account for loss of water from the containment floor to the reactor cavity. Approximately 9 percent of the containment spray flow would be lost to the refueling canal which drained to the reactor cavity. Because SM-1047 was revised near the end of the inspection period, the team did not have an opportunity to review the latest SM-1047 calculation. The team identified review of SM-1047 and comparison of SM-1047 results to calculation 01039.6210-US-(B)-107 as an Inspection Followup Item 50-280/98-201-02."

VIRGINIA POWER RESPONSE

Calculation SM-1047, Revision 2, was issued on March 18, 1998 to address this diversion of water and several other issues which were raised by Westinghouse Nuclear Safety Advisory Letter, NSAL-97-009, "Containment Sump Volume Issues," dated October 27, 1997. The following summarizes the results of Calculation SM-1047, Revision 2, as compared with the results of calculation 01039.6210-US(B)-107.

The purpose of SM-1047, Revision 2, is to determine the water holdup in the reactor cavity after a LOCA. The limiting cases for IRS, ORS and LHSI NPSH are considered. This calculation evaluated the effects of the following phenomena on the available safeguards pumps Net Positive Suction Head (NPSH) following a design basis Loss Of Coolant Accident (LOCA): 1) holdup of spray water in the reactor cavity; 2) recirculation spray piping fill volume; 3) draining condensate films on passive heat sinks in containment; 4) suspended spray droplets in the containment atmosphere. Based on the calculation results, the following penalties must be applied to the current NPSH available results from calculation 01039.6210-US(B)-107. These penalties reflect the integrated effects of the phenomena listed above.

- Outside Recirculation Spray Pumps (ORS): -0.15 ft

- Inside Recirculation Spray Pumps (IRS): -0.16 ft
- Low Head Safety Injection Pumps (LHSI): -0.17 ft

The NPSH available, taking into account these minor penalties, remains acceptable for the IRS, ORS and LHSI pumps. In addition, the phenomena addressed in this calculation have no impact on containment peak pressure, containment depressurization time, containment subatmospheric peak pressure or reported doses for the exclusion area boundary or low population zone.

Changes to the Surry UFSAR are required.

COMPLETION SCHEDULE

The required UFSAR changes to reflect the calculated NPSH analysis penalties will be incorporated into the Surry Safety Injection (SI) system UFSAR change packages compiled under the Design and Licensing Basis Integrated Review program. The UFSAR changes associated with the Safety Injection System, are to be incorporated into the UFSAR by August 31, 1998.

ITEM NUMBER 50-281/98-201-03

FINDING TYPE URI

DESCRIPTION Unit 2 LHSI Pump Minimum Flow (Section E1.2.1.2(g))

NRC ISSUE DISCUSSION

"The team had concerns with the design of the Unit 2 SI system to be able provide adequate minimum flow for continuous LHSI pump operation. The team's review of P&IDs (11448-FM-089A, sh 1, Rev. 53, sh 2, rev 46 and sh 3, Rev. 46) found that the SI system piping configuration was such that there was a potential for pump-to-pump interaction if the discharge pressure of one LHSI pump was stronger than the other pump. Because of the location of the miniflow line which was downstream of the check valves in the pump discharge header, there was a potential for the check valve associated with the weaker pump to become backseated by the higher discharge pressure of the stronger LHSI pump. This would result in a loss of pump miniflow for the weaker LHSI pump and operation of the pump in a dead-headed condition.

Parallel operation of the LHSI pumps would be a concern during those accident scenarios where the LHSI pumps would start and operate but would not immediately inject into the reactor coolant system (RCS). For a small break LOCA, both LHSI pumps would start, but since the reactor coolant pressure was high the pumps would operate in parallel in the minimum flow mode. In this situation, the operators would secure one of the LHSI pumps if RCS pressure was greater than 185 psig per step 13 of the emergency operating procedure (EOP), E-0. According to licensee, the operators would reach step 13 in the EOP no later than 30 minutes into the accident.

The licensee agreed with the team's concern that the SI system design was such that there was a potential for dead-heading the SI pumps. Because the licensee had not ever measured individual LHSI pump flow with both LHSI pumps operating in parallel, the engineers performed an evaluation ME-0375, "LHSI Pumps Minimum Flow Recirculation to RWST With No Flow to Reactor Coolant System During Small Break LOCA," Revision 0, Addendum A to assess this condition. ME-0375 determined that the flow division for the Unit 1 LHSI pumps was satisfactory and above the minimum flow recommended by the pump manufacturer. The pump vendor, Byron Jackson, had informed the licensee in their 8 July 1988 letter that a minimum flow of 150 gpm was originally specified for the LHSI pumps. The evaluation indicated that the flow between the Unit 1 LHSI pumps were evenly balanced with 52 percent of the total flow (201 gpm) being provided by one of the LHSI pumps and the remainder, 48 percent of total flow or 182 gpm, being provided by the second LHSI pump.

Evaluation ME-0375 also showed that the flow division between the Unit 2 LHSI pumps did not ensure minimum pump flow requirements through both pumps. The evaluation calculated that there was a flowrate of about 95 percent (359 gpm) through the stronger

pump with the remainder of flow (5 percent or about 18gpm) going through the weaker Unit 2 LHSI pump. Because the weaker Unit 2 LHSI pump (2SI-P-1A) could not provide the minimum pump flow of 150 gpm when both LHSI pumps were operating in parallel, the licensee performed an evaluation ET.CME 98-014, "Evaluation of Operation of LHSI Pumps Recirculating to the RWST," Rev. 02, March 24, 1998, to determine the operability of the 2SI-P-1A pump. The licensee concluded that the 2SI-P-1A pump was operable based on the following:

- There was documented evidence to demonstrate that the LHSI pumps have accumulated about 65 minutes of operation in low flow conditions with no observable adverse effect on their performance. The licensee conducted a review of past LHSI pump operation and found that there had been about seven instances of SI actuations in which the LHSI pumps had operated in the minimum recirculation flow mode. The maximum documented SI duration was for 25 minutes on February 2, 1975.
- A review of periodic surveillance tests and work orders for the 2SI-P-1A pump showed that the pump performance had not degraded, and pump vibration readings were normal.
- "Flashing" at the low flow condition of 18 gpm was calculated to occur at around 60 minutes into the low flow condition. Under the scenario where both LHSI pumps were operating under minimum flow conditions, the licensee estimated that the operators would secure one of the LHSI pump within 30 minutes into this event. The licensee estimate of 30 minutes was based on the time it would take the operators to reach a section in the EOP which required operators to make a decision on whether both LHSI pumps were necessary.

The team agreed that operator intervention to secure one of the two Unit 1 LHSI pumps within 30 minutes to preclude the potential for pump-to-pump interaction was a reasonable resolution to this design deficiency. However, the team needed to review the licensee's long term resolution to the pump-to-pump interaction issue with the Unit 2 LHSI pumps. The team concluded that lack of test data which demonstrated pump operability with significantly reduced minflow and the pump's inability to pass vendor recommended minflow were potential operability concerns. The licensee issued DR 98-0660 to take corrective actions. The team identified the licensee's long term resolution to the Unit 2 LHSI pump minimum flow issue as URI 50-281/98-201-03.

The team also determined that the licensee's response to IE Bulletin 88-04 was inadequate in that their response (VEPCo letter of August 8, 1988, serial no. 88-275A) failed to identify that there was pump-to-pump interaction issue associated with the Unit 2 LHSI pumps which could result in near dead-headed condition for the 2SI-P-1A pump."

VIRGINIA POWER RESPONSE

Background

The two Low Head Safety Injection (LHSI) pumps for each unit share a common recirculation line to the Refueling Water Storage Tank (RWST). The recirculation line ensures that there is a flow path for the pumps in the event that the pumps are started when Reactor Coolant System (RCS) pressure is greater than the shutoff head of the pumps. This can occur during injection phase following a Small Break LOCA or following the receipt of an erroneous SI initiation signal. The recirculation line is also used to perform quarterly testing of the pumps.

Westinghouse indicated in a letter that the LHSI pumps purchased for Surry Power Station had very flat Total Developed Head (TDH) curves and pointed out that there might be a problem operating the two LHSI pumps in parallel discharging to the RWST through the common minimum flow recirculation line. In 1988, a test was performed on the Surry Unit 1 LHSI pumps in response to the Westinghouse letter. The test ran each pump individually on recirculation and gathered information on flow, head and vibrations, then ran the two pumps in parallel and gathered information on flow and head, to determine if a strong/weak pump relationship exists. The test demonstrated that there was little difference between the performance of the two pumps and, thus, the ability of the two LHSI pumps to operate in parallel discharging through a common recirculation line without one pump deadheading the other. The vibration data, taken on the pumps operating individually on both recirculation lines, was well within specification. No vibration data was taken while the two pumps were running in parallel. The results of the tests were forwarded to Byron Jackson (BW/IP), the original supplier of the LHSI pumps, for their evaluation.

BW/IP confirmed that the existing Surry LHSI pump miniflow lines are adequate for parallel and single pump operation based on current operating practices and repair history, but cautioned against operation with a pump discharge valve shut. The manufacturer pointed out that the original minimum recirculation flow for the LHSI pumps was 150 gpm per pump, based only on thermal concerns. They now recommend a minimum recirculation flow of about 30 percent of rated flow to address hydraulic instabilities as well as thermal concerns, if the pump is to be run for extended periods of time (i.e., hours) on the recirculation line. BW/IP pointed out that since the head capacity curve for the Surry LHSI pumps are essentially flat for flow rates of less than 500 gpm, it is possible for one pump to reduce the flow through the companion pump to levels less than 150 gpm in a circumstance where one pump was severely limited in capacity because of excessive wear or some other factor.

NRC IE Bulletin 88-04, was issued on May 5, 1988. The NRC IE Bulletin requested:

> ". . . all licensees to investigate and correct as applicable two miniflow design concerns. The first concern involves the potential for the dead-heading of one or more pumps in safety-related systems that have a miniflow line common to two or

more pumps or other piping configurations that do not preclude pump-to-pump interaction during miniflow operation. A second concern is whether or not the installed miniflow capacity is adequate for even a single pump in operation."

Engineering evaluated the LHSI pump recirculation lines and forwarded the results of the evaluation in a Technical Report to Surry Power Station on August 8, 1988. Information in the report was included in the Virginia Power reply to the NRC on IE Bulletin 88-04.

Since the miniflow recirculation line for the two LHSI pumps was originally sized for thermal protection rather than to preclude possible hydraulic instabilities, Virginia Power conservatively determined that the Surry LHSI system design would not support continuous operation in dual pump configuration. However, it was concluded that the design of the LHSI system is adequate for the modes and duration of operation expected under normal and accident conditions. Because the piping configuration for the LHSI miniflow recirculation line does not preclude pump interaction during parallel operation, and the LOCA analysis assumes only one operating LHSI pump, it was further concluded that, if conditions warranted, the second LHSI pump can be secured.

As a result of an NRC commitment in NRC IE Bulletin 88-04, Virginia Power performed an evaluation of a small break LOCA scenario on the simulator to verify that the Surry Emergency Operating Procedures (EOPs) adequately address and, therefore, minimize operation of the LHSI pumps in the recirculation mode. It was determined that an emergency procedure revision was necessary to ensure that one LHSI pump will be secured within 30 minutes when operating in parallel with low flow conditions. The EOP was revised to secure one LHSI pump during recirculation only flow conditions.

Discussion

As a result of the NRC A/E Inspection questions, which relate to operation of the Surry LHSI pumps on the minimum flow recirculation line to the RWST, Engineering has re-evaluated Virginia Power's previous responses to NRC IE Bulletin 88-04. Building on the test that was conducted in 1988, Mechanical Engineering prepared a calculation to confirm the conclusions drawn from the test.

The original vendor witness curves for the Unit 1 pumps were reviewed. The curves show that the Unit 1 pumps are well matched at flows less than 500 gpm, so deadheading of one pump by the other is not a concern when operating in parallel with flow directed to the RWST through the recirculation line. The calculational results indicate that the flow split for these two pumps when recirculating to the RWST is about 52% for the strong pump and 48% for the weak pump. Thus, both pumps will flow at least the 150 gpm recommended by the pump vendor. Also, the recent pump test data for the two Unit 1 pumps confirm that the pump heads have not degraded. The analysis supports the conclusion that the minimum flow recirculation line for Surry Unit 1 LHSI pumps is adequate for the modes and duration of operation expected under normal and accident conditions.

No parallel operation testing was performed on the Unit 2 pumps in 1988, as it was assumed that the Unit 1 configuration was typical for both units. However, a review of the Surry Unit 2 LHSI pump curves indicates that these pumps are not as well matched as the Unit 1 pumps at flows less than 500 gpm.

The original vendor witness curves for the Unit 2 pumps were reviewed. The curves show that 2-SI-P-1A is a "weak" pump with a Total Developed Head (TDH) at shutoff about 5 feet less than 2-SI-P-1B. The stronger 'B' pump will provide the majority of the recirculation flow at flows less than 350 gpm. Calculational results indicate that the flow split for these two pumps when recirculating to the RWST is about 95% for the strong pump and 5% for the weak pump. Because the recirculation flow for the 'A' pump would be much less than that recommended by the vendor, further review of the history of the pump's performance and maintenance was conducted.

It was found that the 5-foot difference in TDH between pumps 2-SI-P-1A and 2-SI-P-1B has existed since original installation and is not the result of degradation of pump 2-SI-P-1A. In addition, recent pump test data for the Unit 2 pumps confirm that the pump heads have not degraded or significantly diverged from the original performance. A review of the operating history and maintenance records for the Unit 2 LHSI pumps was then performed.

A review of operating history since Surry startup revealed that there have been about seven SI activations for Unit 2 with the RCS at operating pressure. During each of these activations, both pumps started aligned to recirculate to the RWST with no feed forward to the RC system. Records indicate that for the inadvertent SI activations on 2/2/75 (duration 25 minutes), 8/22/80 (duration 9 minutes), 10/10/82 (duration 16 minutes), 3/27/88 (duration 6 minutes), and 8/2/91 (duration 9 minutes), the Unit 2 LHSI pumps operated in parallel recirculating to the RWST for a total of 65 minutes. It should be noted that the operating times reported are minimum times since the log entries record only the initiation of SI and SI reset, not the time when the LHSI pumps were secured. Once the reset is accomplished, initial operator attention is directed toward securing HHSI flow and returning the Charging/HHSI pumps to their normal alignment. Therefore, the actual elapsed time from SI initiation until the LHSI pumps were secured was longer and may have exceeded 30 minutes for the early SI activations.

It would be expected that in response to an actual SB LOCA, one of the LHSI pumps would be secured in less than the times noted above for the inadvertent SI activation. The EOPs require that one LHSI pump will be secured when operating in parallel with low flow conditions. In correspondence with the NRC in response to IEB 88-04, we indicated that this action would take place in less than 30 minutes. However, discussions with Surry Training indicates that for normal training scenarios, the second LHSI pump is secured in 10 to 15 minutes and that for more complicated training scenarios, the second LHSI pump is secured in 15 to 20 minutes.

A review of work orders for Surry Unit 2 LHSI weak pump, 2-SI-P-1A, since unit startup has shown that the pump has not been pulled for maintenance on the rotating elements since 1980, when modifications were made to their suction bell which resulted from model testing of the North Anna LHSI pumps. Periodic test data for the past several years indicates that pump performance has not degraded and pump vibration readings have been normal.

Since the data seems to contradict conventional wisdom that damage to the pump is likely at very low recirculation flows, a review of the installed configuration was performed to identify any design or operating features that would mitigate the effects of low flow operation.

Pump Design

The Surry LHSI pumps are Byron Jackson (BW/IP) Model 18CKXH two stage vertical pumps. The pumps outer casing is a cylinder about 53 feet long encased in concrete with a 12 inch suction connection located about 7 feet from the bottom of the pump casing and a mounting flange for the pump assembly at the top. It can be seen from the pump vendor drawings that the pump is of a robust design. The pump has a 2.187 inch diameter shaft. Shaft bearings are included at the tail shaft, between the two stages, at the outlet of the 2nd stage, as well as at intermediate points on the vertical shaft. This arrangement of bearings provides a high degree of stability to the impellers. Running clearances of the wear rings are greater than those of the bearings. The combination of multiple bearings in the pumping section and large wear ring clearances results in a pump that is very tolerant of conditions that might cause rubbing of the wear rings. The pump discharge column connects the discharge from the pump 2nd stage to the pump discharge head assembly and supports the non-rotating portions of the pump.

The pump operates at 1800 RPM and has stainless steel impellers that are designed to produce the rated flow with a required NPSH of only 17.5 Ft.

Operating Conditions

Case 1 – Low Flow Through The Pump

In a low flow situation we would normally expect flow recirculation within the pump impeller which could increase pump vibrations and, if the pumps operate for long periods at low flows, the temperature of the water in the pump could increase enough to flash. However, during the inadvertent SI activations discussed above or during any postulated SB LOCA, the two LHSI pumps are recirculating to the RWST pumping cold water (45°F) and are operated with about 108 foot head on the pump suction (TS minimum RWST level to pump suction 1ST stage impeller centerline elevation). The saturation temperature at this pressure is about 295°F. Since the LHSI pump supply from the RWST is at 45 degrees and is designed for operating temperatures of 230°F, we can stand a substantial temperature rise across the pump with no concern for bearing or wear ring clearances.

Since the LHSI pump casing is encased in concrete, which is buried in the ground, the water initially inside the pump casing would be at the ground temperature of about 55°F. After the pump starts, the replacement water from the RWST will be at a temperature of 45°F. Therefore, at a flow of 18 gpm through the pump, we would expect an initial temperature rise of the water across the pump impellers from 55°F to about 102°F. The design temperature of the LHSI pump is 230°F so the 102°F temperature is well within the design temperature of the pump. Also, since the saturation temperature of the water at the 1st stage impeller is about 295°F, due to the static head of water from the RWST, we would not expect flashing in the pump suction.

A calculation of the temperature distribution in the pump after 30 minutes was performed assuming heat transfer from the water in the pump discharge column to the water in the pump casing outside the column. The calculation assumes that all heat from the motor horsepower at pump shutoff head is used to heat the water in the pump bowls and that no heat is transferred to the surrounding concrete. Also, the cooling effect of the 45°F water coming in from the RWST is ignored. For these conditions, the bulk temperature of the water in the pump discharge column would be about 135°F and the temperature in the pump casing outside the column would be about 101°F. Again, this temperature is well within the design temperature of the pump.

This would explain why the pump has not sustained any damage at the calculated flow of approximately 18 gpm.

Case 2 – No Flow Through The Pump

Although performance data and calculations indicate that there would be flow through the "weak" pump, there are sufficient uncertainties in both such that it cannot be shown conclusively that there is flow through the 'A' pump when operated in parallel with the 'B' pump on the recirculation line. Therefore, an evaluation was performed to consider this possibility.

As mentioned above, water is supplied to the LHSI pumps from the RWST so the pressure at the pump suction due to the static head between the RWST and pump suction elevations is 47.4 psig (62.1 psia). The saturation temperature at 62.1 psia is 295°F, so we would expect flashing in the pump casing when the water in the casing reaches this temperature. If the temperature inside the pump increases 68.6°F/min due to energy added to the water in the pump by the motor, the time required to flash the water in the pump bowls would be 3.5 minutes. It appears that water inside the pump bowls would flash to steam in about 3.5 minutes if there was no flow through the pump. However, we have experienced parallel operation of the pumps as a result of SI activations ranging from at least 6 minutes to in excess of 25 minutes for Unit 2, and have not experienced failure or damage to the pumps.

The explanation for this again lies with the design and installed configuration of the pump. Because this is a vertical pump, and there are large columns of relatively cool

water on both the suction and the discharge sides of the pump, any voids caused by flashing in the pump bowl are rapidly filled. In the absence of actual flow through the pump, natural circulation currents would be created in the discharge column and casing since the heat addition is at the bottom of the pump. These currents will rapidly remove the heat from the pump bowls and, thus, minimize voiding. As noted above, the bulk temperature of water in the pump discharge column would only reach approximately 135°F in 30 minutes, the maximum time required to secure one LHSI pump. The effects of vibrations caused by voiding are mitigated by the robust design of the bearings and, therefore, rubbing of the wear rings is prevented. Because the pump operates relatively slowly (1800 RPM) and is designed to operate with a relatively low required NPSH at design flow (17.5 Ft.), voiding in the pump does not cause impeller damage characteristic of high-energy cavitation. Instead, the impeller would be subject to long-term erosion, which is not a concern for the short period of operation described here.

Following the period of parallel operation, the weaker 'A' pump is either shut down and potentially restarted later, or the stronger 'B' pump is shut down and the 'A' pump has exclusive use of the recirculation flow path. In either case, the pump is expected to operate normally and fulfill its safety function.

Therefore, it could be concluded that:

There has been some flow through the "weak" 2-SI-P-1A pump during the past SI activations, (and will be in the future since testing of the pumps have not shown any degradation of the pump performance) and this low flow was sufficient to prevent flashing in the suction and damage to the pump,

or

We have operated the "weak" 2-SI-P-1A pump at shutoff with no flow and the robust design of the pump and its installed configuration mitigates any effects of voiding in the pump bowl. There was no short-term damage as a result of the operation.

Conclusions

Calculations recently performed confirm the conclusion of the 1988 Engineering Report, that the minimum flow recirculation line for Surry Unit 1 LHSI pumps is adequate for the modes and duration of operation expected under normal and accident conditions. However, this is only because the pumps are currently well matched. A change of only a few feet of TDH on one pump would result in a flow imbalance in Unit 1 similar to Unit 2.

The Surry Unit 2 LHSI pumps are not as well matched as the Unit 1 pumps at flows less than 500 gpm. Calculations show that the 'A' LHSI pump is subjected to less than the recommended minimum flow when both pumps are operated in parallel using only the recirculation flow path. Operating history of the SI system since Unit 2 startup and maintenance history of the "weak" LHSI pump (2-SI-P-1A), which has operated for

periods from 9 minutes to in excess of 25 minutes on recirculation in parallel with the strong pump, has demonstrated that it can operate in this mode for the expected period of time during a SBLOCA without damage. Results from 2-OPT-SI-005, LHSI Pump Test (quarterly periodic tests on minimum recirculation to the RWST) and the most recent periodic test for pump 2-SI-P-1A from 2-OPT-SI-002, Refueling Test of the Low Head Safety Injection Check Valves to the Cold Leg, (tests at full flow injecting to the RC System during refueling outage) confirm that pump 2-SI-P-1A has not degraded and will supply the LHSI flows assumed in current LOCA analysis. Based on the above information, it is concluded that the Surry Unit 2 LHSI pumps are capable of performing their intended function.

Resolution

Although the LHSI pumps are operable, a modification package will be prepared to address the susceptibility of the LHSI Pumps to interaction during periods when the pumps are operated in parallel on the recirculation flowpath with no forward flow. At a minimum, the modification will relocate the recirculation line tie-in for each pump from their present position, in a common line downstream of the pump discharge check valve, to a point upstream of the check valve. This will prevent the potential situation where a "strong" pump has exclusive use of both recirculation lines and the associated "weak" pump is operated with low flow. The modification package will be implemented during the 1999 Refueling Outage for Unit 2 and the 2000 Refueling Outage for Unit 1.

In addition, a review of Virginia Power's response to NRC IEB 88-04 (both Stations) will be conducted to assess the thoroughness of the response and, thus, ensure that there are no other pumps that are susceptible to potentially harmful interactions. This review will be completed by October 1, 1998 and a revised response submitted, if necessary.

COMPLETION SCHEDULE

A modification package will be implemented during the 1999 Refueling Outage for Unit 2 and the 2000 Refueling Outage for Unit 1 to resolve the susceptibility of the LHSI Pumps to interaction during periods when the pumps are operated in parallel on the recirculation flowpath.

Virginia Power's evaluations performed in response to NRC IEB 88-04 will be reviewed to ensure that there are no other invalid assumptions regarding pumps that are susceptible to potentially harmful interactions. This review will be completed by October 1, 1998 and a revised response submitted, if necessary.

ITEM NUMBER 50-280/98-201-04

FINDING TYPE IFI

DESCRIPTION Motor Thermal Overload for 1-S1-P-1B Pump (Section E1.2.2.2.1(d))

NRC ISSUE DISCUSSION

"The team reviewed the safety evaluation which was used to document the replacement of 1-SI-1P-B motor performed under work order EWR 88-072. The original 250 HP motor for LHSI pump, 1-SI-P-1B, was replaced with a larger 300 HP motor. The replacement motor required a minimum starting voltage of 75 percent at the motor terminals compared to the original motor that required 70 percent voltage. Calculation EE-0034, "Surry Voltage Profiles," Rev. 01 determined that adequate voltage was available at the motor terminals to enable the motor to start. However, calculation EE-0038, "Electrical Power Review of 1-SI-P-1B Motor Replacement", Rev. 0, determined that adequate motor thermal overload protection at the higher current ranges could not be provided for the replacement motor with the existing breaker.

The safety evaluation concluded that due to limitations of the operating bandwidth of the overcurrent protection device, the thermal protection of the motor could not be assured under certain conditions. The licensee stated that providing adequate thermal protection was not as critical as ensuring that the 1-SI-P-1B pump would start and operate when required. The team's review of the SI pump thermal protection issue will be an Inspection Followup Item 50-280/98-201-04."

VIRGINIA POWER RESPONSE

As stated above, providing adequate thermal protection is not as critical as ensuring that the Safety Injection (SI) pump starts and operates when required. The bandwidth associated with the overcurrent protective device for the 1-SI-P-1B motor does not permit 100% thermal protection of the motor under short circuit/locked rotor conditions. Assuring starting and running capability for the motor, as opposed to providing motor thermal protection, is proper for a motor as important to the plant safety analysis as the Low Head Safety Injection pump. It has been determined that improvements can be made which will continue to assure operation while providing full range thermal protection of the motor.

The operability of the motor is unaffected by the lack of complete protection. The motor may experience greater damage during a short circuit/locked rotor condition than if the trip device had removed the motor from service. In either case, the motor is no longer available due to this single failure condition. The existing protection is designed to ensure the continued operation of the pump/motor, during all normal and accident conditions, in order to perform its safety function.

The short circuit/locked rotor protection concerns associated with the 1-SI-P-1B motor will be resolved by revising Calculation EE-0497 to specify new Long Time Delay/ Instantaneous (LTD/INST) trip settings for the breaker. A Design Change Package (DCP) will be written to implement the new LTD/INST trip settings by modifying or replacing the breaker, as required, associated with the 1-SI-P-1B pump motor.

COMPLETION SCHEDULE

Calculation EE-0497 will be revised by November 15, 1998.

The Design Change Package (DCP) to install the new LTD/INST trip settings by modifying or replacing the breaker, as required, associated with the 1-SI-P-1B pump motor, will be implemented by June 30, 1999.

ITEM NUMBER 50-280/98-201-05

FINDING TYPE IFI

DESCRIPTION Adequacy of 4160 VAC Electrical Cables to Withstand Fault Current (Section E1.2.2.2.1(e))

NRC ISSUE DISCUSSION

"The team determined that #1 and #2 AWG cable sizes which were used to supply electrical power to the high head safety injection, auxiliary feedwater, component cooling water and residual heat removal pump motor loads from the 4160 VAC bus were not adequately sized to carry the fault current on the 4160 VAC bus. The team was concerned with the potential damage to the cables before the breakers could operate and isolate the fault. The team reviewed a preliminary evaluation performed by the licensee to determine the cable conductor temperature rise due to exposure to the available fault current, and concluded that either the up-stream breaker would operate to isolate the fault or the cable conductor would fail. Although the cables in question are per original design, because of the possibility of cable failure from fault currents, the team identified the acceptability of this cable design as Inspection Followup Item 50-280/98-201-05."

VIRGINIA POWER RESPONSE

Virginia Power agrees that documented verification of the ability of 4160 VAC cables to withstand postulated fault currents will add to our confidence in our original design.

To determine the adequacy of 4160 VAC electrical cables to withstand fault current, two types of faults are considered. They are ground faults and three phase faults.

Ground faults, which are most likely to occur of the two postulated faults, are not a problem since their short circuit current will be limited by the distribution system grounding resistance. This is true since these faults could be caused by either a phase to ground short in a motor winding or by a local cable insulation failure which would result in a single phase to ground fault.

Three phase faults, while assumed to be least probable, will generate the highest short circuit current. For our specific application, the cable sizes involved will either vaporize or quickly melt. In either case, existing overcurrent devices are set to interrupt the fault in approximately 5 cycles. This short duration is not believed to be long enough to support the ignition of the cable. We have discussed this issue with Stone and Webster, and based on their experience from testing cable under similar overload conditions, the cables do not instantaneously ignite. A sustained overcurrent condition must exist for ignition to occur.

In order to further assess this situation, cables from Emergency Bus 1H were analyzed. These cables are typical for each of the other Emergency Buses. Cables affected were:

1H4PH1	Triplex #2	aluminum	220'	feeder for the Auxiliary Feedwater pump
1H5PH1	3/C #1	aluminum	200'	feeder for the A Charging pump
1H6PH1	3/C #1	aluminum	200'	feeder for the C Charging pump
1H7PH1	3/C 500mcm	aluminum	50'	feeder for load center transformers
1H10PH1	3/C #1	aluminum	160'	feeder for the Component Cooling pump
1H11PH1	3/C #2	aluminum	365'	feeder for the Residual Heat Removal Pump

The EDG feeder cable was neglected since they are also larger than the minimum size discussed in the original portion of the response.

Breaker operating times of 5 cycles were conservatively used. Acceptable conductor temperature per the EPRI guide book is 250 degrees Celsius. Per IEEE 242-1986, the minimum size aluminum conductor fed from 4 KV bus should be 250 MCM to meet its requirements. (Surry is not committed to IEEE 242.) Therefore, the 500 MCM aluminum feeder for the load center is acceptable. (Note: The "I squared T" for this cable is calculated to be 167 degrees Celsius, which conforms to the IEEE guideline.)

For the #1 and #2 AL cables, the "I squared T" values have resulted in temperatures of 3352 degrees Celsius and 14,267 degrees Celsius being calculated for faults at the bus. These values exceed the boiling point for aluminum, (e.g. 2454 degrees Celsius, Note: melting point temperature is 660 degrees Celsius). It is expected that these conductors will therefore vaporize rather than propagate flame and induce fire in the raceway system. For faults at the load, Virginia Power conservatively looked at the AFW, CH and RHR feeds based on their cable type and circuit length. The results indicate conductor temperatures of 1466 degrees Celsius, 1354 degrees Celsius and 540 degrees Celsius, respectively. It is expected that the AFW and CH feeders will therefore melt and act like fuses to interrupt the current. Assuming a more realistic breaker opening time of 7 cycles for the RHR feeder, will result in a conductor temperature higher than the melting point.

It should be noted that the RHR pumps are not used in normal operation or in any accident response. They are generally used to bring the unit to cold shutdown. There were no other cables sized between #1 and 500 MCM fed off of the 4KV bus, therefore, no other cable types were evaluated.

Based on the above, there is no operability or fire concern related to these cables. A formal Technical Report will be generated to document the acceptability of the 4KV cable design.

COMPLETION SCHEDULE

A Technical Report will be issued by December 1, 1998 to document the acceptability of the 4KV cable design.

ITEM NUMBER 50-280/98-201-06

FINDING TYPE IFI

DESCRIPTION Breaker-to-Breaker and Breaker-to-Fuse Analysis (Section E1.2.2.2.1(f))

NRC ISSUE DISCUSSION

"The team's review of the Calculation EE-0497, "SR 480V Load Center Coordination", Rev. 0 revealed that breaker-to-breaker or breaker-to-fuse coordination evaluations were not performed for all Class 1E circuits. The calculation had concluded that these additional coordination evaluations needed to be performed. The licensee informed the team that these additional evaluations had not been performed. An action item SR-38-EP-99.10 was initiated to complete the remaining evaluations. Review of the licensee's breaker-to-breaker and breaker-to-fuse coordination is results considered Inspection Followup Item 50-280/98-201-06."

VIRGINIA POWER RESPONSE

Calculation EE-0497, "SR 480V Load Center Coordination," concluded that additional breaker-to-breaker coordination is needed (no breaker-to-fuse coordination issues were identified), however, none of the problems identified were safety significant. The existing settings are acceptable based on current operating and calculated accident loading. Therefore, no operability issues exist.

Virginia Power will provide additional tripping margin, as required, between the individual motor feeders and actual motor Full Load Current/Locked Rotor Current (FLC/LRC). In addition, the overcurrent setpoints for the MCC supply breakers will be increased, as required, such that the breaker settings do not limit load below the MCC ratings. This will be accomplished by revising calculation EE-0497 and preparing a DCP to implement the setpoint changes and replace affected trip devices as required.

These changes will assure that breaker to breaker coordination provides appropriate electrical system protection.

COMPLETION SCHEDULE

Calculation EE-0497 will be revised by November 15, 1998.

A Design Change Package (DCP) will be generated to provide additional breaker-to-breaker coordination, to support implementation by the end of the 2000 Unit 2 and 2001 Unit 1 refueling outages.

ITEM NUMBER 50-280/98-201-07

FINDING TYPE IFI

DESCRIPTION Breaker Replacement (Section E1.2.2.2.1(g))

NRC ISSUE DISCUSSION

"The team noted that at Surry all electrical penetrations were protected with only one breaker per original design. The review of the technical reports, EE-0094 & EE-0095 revealed that for several of the penetrations the existing breakers did not provide adequate protection. The technical report had recommended replacement of the breakers providing inadequate protection. The team was informed that installation of all breakers was not complete and was being done under a generic breaker replacement package DCP 92-099. The team's review of the licensee's actions to replace selected breakers under DCP 92-099 is considered Inspection Followup Item 50-280/98-201-07."

VIRGINIA POWER RESPONSE

Technical Reports EE-0094 and EE-0095 document the evaluation of electrical containment penetrations for protection against short-circuit conditions and overload conditions. These reports document that the identified exceptions to proper protection are not considered serious due to the nature of the loads served by these circuits. In addition, the areas not fully protected are generally small. In the event of a short-circuit, the lack of protection would most likely result in decreased qualified life, not total failure. Therefore, the existing circuit breakers are capable of preventing penetration and seal damage to the extent that they will protect the integrity of the containment in the event of a short-circuit failure. There are no operability concerns with this protection issue.

Work scope additions to DCP 92-099 are being prepared to replace existing breakers with the correct size breaker IAW Technical Reports, EE-0094 and EE-0095. Replacement of the improperly sized breakers will be performed by the end of the next refueling outage for each unit.

COMPLETION SCHEDULE

Unit 1 breakers will be replaced by the end of the Fall 1998 refueling outage.
Unit 2 breakers will be replaced by the end of the Spring 1999 refueling outage.

ITEM NUMBER 50-280/98-201-08

FINDING TYPE URI

DESCRIPTION EDG Battery Transfer Switch (Section E1.2.2.2.2(a))

NRC ISSUE DISCUSSION

"The team asked the licensee to provide the original design basis and any design changes to the EDG batteries' transfer scheme. Surry EDG battery design was such that the field flash and control circuits of either EDG 1 or 2 could be manually transferred in accordance with emergency operating procedures (EOPs) to another DC source, EDG 3 battery. After a completed manual transfer, the affected circuitry for either EDG 1 or EDG 2 and EDG 3 will be supplied from EDG 3's battery. The licensee determined that the EDG batteries' transfer scheme was the original design and that the only design change was to add fuses in the control circuits for the batteries to perform redundant-train isolation. The team identified the following concerns for this circuitry:

- No analysis was available which demonstrated that EDG 3's battery was able to supply the field flash and control circuits of more than one EDG. As stated in Section E.1.2.3.2.e., calculation 14937.28, "Verification of Lead Storage Battery Size for Emergency Diesel Generators", Rev. 2 sized each EDG battery to supply the field-flash and control circuits for one EDG for two hours of operation.
- The use of EDG 3's battery to supply two operating EDGs may potentially lead to a common mode failure. Because there was no analysis which demonstrated that EDG 3's battery can successfully start and operate both EDGs simultaneously, in the event that the transfer switch was used to power an EDG with a faulted battery, this situation could result in the failure of both trains of EDGs (the EDG with initially faulted battery and EDG #3).
- The actual operation of these switches may violate the licensee's separation criteria between trains. The Surry plant standby power systems were evaluated against IEEE 308-1974 in the original Safety Evaluation Report (SER); and the licensee based the acceptability of the plant's onsite voltages in accordance with the stated criteria in IEEE 308-1974. That document in Section 5.3.2(3) states that "DC distribution circuits to redundant equipment shall be physically and electrically independent of each other." Presently when a transfer is made, redundant 125 VDC load groups are connected to a singular DC source.
- The operation of a transfer switch may be undetected. The team was concerned that there was a potential for the transfer switch to be out of its normal position because there was no local or remote annunciation which indicated that the switch is out of its normal position. In addition, the operators were not required to check the proper position of the switch during their normal outside tours. However, the operators do check once a month that the switch is in the proper place as part of their "blue tag" verification program. The licensee decreased the probability of a transfer switch's misposition by installing a "blue" tag on each switch allowing it to be operated only with the Shift Supervisor's permission.

The licensee initiated DR S-98-0605 to evaluate and disposition this concern but did not conclude its review during the inspection.

The team considered the design of the EDG battery transfer scheme a potential unreviewed safety question (USQ) since the transfer-scheme was not discussed in the UFSAR and may not have been reviewed by the NRC. The UFSAR states each EDG was supplied by an independent control battery and that the independence of the EDG's batteries and starting circuits increases each EDGs' reliability. The basis of a USQ would be that the use of the transfer switch would create a malfunction of equipment important to safety of a different type than evaluated previously in the UFSAR. Although the common mode failure of the EDGs for a unit is evaluated in the UFSAR under an SBO, this analysis is outside the design basis accident envelope and its initiating cause is not the failure of an improperly sized EDG battery. The licensee's evaluation pertaining to the design adequacy of the transfer switch and the determination of whether the design of the EDG transfer switch constitutes a potential USQ is considered an Unresolved Item 50-280/98-201-08."

VIRGINIA POWER RESPONSE

Virginia Power agrees that the design of the EDG battery transfer switch would require further evaluation prior to use. As an original plant feature to provide emergency or abnormal operating flexibility, the switch was not intended to be used during normal operating conditions. In fact, with the possible exception of testing as part of the operational readiness program to support plant restart activities in the late 1980's, we have found no other evidence that this switch has ever been used. Reassessment of this feature from a risk perspective would likely conclude that the potential risk of common mode failure exceeds the benefit of flexibility in contingent actions. Accordingly, rather than analyze the current installation for use, Virginia Power has disabled the switch by locking the switch in the "open" position. A Design Change Package will be generated to permanently disable the switch.

As a note of clarification, this feature was initially constructed prior to issuance of IEEE 308-71 and the original review of electrical and I&C issues by the NRC was conducted in the time frame of the issuance of IEEE 308-71. Notation in the NRC discussion of Surry being evaluated to IEEE 308-74 is incorrect. The relevant IEEE 308 reference does not distinguish "physical and electrical" independence. We surmise that only electrical independence was confirmed when the electrical system was initially reviewed in the Operating License process.

COMPLETION SCHEDULE

Virginia Power has disabled the switch by locking the switch in the "open" position.

A Design Change Package (DCP) will be generated to support permanently disabling the switch. The switch will be permanently disabled by June 30, 1999.

ITEM NUMBER 50-280/98-201-09

FINDING TYPE URI

DESCRIPTION DC Tie Breaker (Section E1.2.2.2.2(b))

NRC ISSUE DISCUSSION

"The main DC buses are capable of being connected together by a molded-case switch which has no overcurrent or fault protection. During normal operation each main DC bus is supplied by two battery chargers with a station battery floating on that bus. The buses are only tied together, during plant shutdown for maintenance on one of the batteries, to prevent loss of either DC main bus even momentarily. Calculation EE-0499,"DC Vital Bus short Circuit Current," Rev. 1 analyzes for the maximum fault current at the main DC buses with four chargers and one battery connected to the tied main DC buses. The combined fault contribution of two batteries connected to a common DC bus has never been evaluated in Calculation EE-0499.

UFSAR page 8.4-5 states that parallel operation of the DC buses is permitted when either battery is out for maintenance. Maintenance operating procedure (MOP) 1-MOP-EP-030, "Removal from Service and Return to Service of Station Battery 1A", rev 0, step 5.1.3 allows the molded-case tie switch to be closed with both batteries connected to the bus. Although there is a caution statement before step 5.1.3 which warns the technicians to minimize the time the DC busses are cross-tied with both batteries tied to the bus, the team considered that there was sufficient potential for a bus fault to develop across the load side terminals of a breaker housed in a main DC bus (approximately 30 to 60 minutes) while in this situation.

The licensee performed a preliminary calculation during the inspection that showed, for either unit, the worst case fault current with both batteries connected to a common DC bus was over 30,000 amps. That value is well above the interrupting rating of 22,000 amps for the main DC bus breakers. By permitting the tie switch to be closed with both batteries on a common bus, the licensee has operated the plant outside of its design basis because the evolution was not supported by the existing UFSAR or the present fault current analysis for the main DC buses. The licensee has agreed with this assessment by the team and issued DR S-98-0719.

The team considered this issue as another potential USQ because the potential failure sequence appeared to be of a different type of equipment malfunction than evaluated in either the current UFSAR or the existing design basis analysis. Neither of those documents permitted both station batteries to be simultaneously connected to the cross-connected DC buses. The team was informed by the licensee that an earlier version of the UFSAR - prior to DCPs 85-32 and 85-34 which performed DC vital bus expansions for Unit 1 and Unit 2 respectively - permitted parallel operation of batteries and chargers. Because the earlier version of the UFSAR allowed parallel operation of batteries and chargers to the DC bus, the licensee believed that this type of battery alignment can continue to be performed without the evolution resulting in a USQ.

However, the team's conclusion was that the earlier version of the UFSAR was no longer applicable to the current DC system. It appeared to the team that the UFSAR change regarding battery alignment limitation was made to recognize the newer and more capable batteries installed under DCPs 85-32 and 85-34. The team's review of the design changes contained in DCPs 85-32 and 85-34 found that the modification upgraded the capacity of the station batteries from 1500 to 1800 amp-hours. With increased battery capacity, it was no longer possible to interrupt the fault current using the main DC bus breakers. Although the main DC bus breakers interrupting capability was increased in the same modification, the increase was not sufficient to adequately interrupt the fault current from both sets of batteries. Both the current UFSAR and design basis analysis took this conservative viewpoint. However, the safety evaluations for DCPs 85-32 and 85-34, and those for subsequent revisions to pertinent MOPs (1-MOP-EP-30 and 204) did not address the safety aspects of operating with the more capable station batteries in parallel. It appeared to the team that the previous UFSAR description which had allowed parallel battery operation to the DC busses with the DC cross-ties shut did not necessarily preclude the potential for this previously acceptable alignment to be considered a potential USQ issue in the new modified DC system. The team concluded that the previously accepted DC alignment may pose a potential USQ since the design was changed and operation of the DC system in other than presently described in the UFSAR warrants new reviews by both the licensee and the NRC.

The licensee is evaluating this issue under DR S-98-0719. A fault current above the DC breaker's interrupting capacity is a new type of equipment malfunction which makes the total loss of DC power, never evaluated in the UFSAR, credible because the common DC bus voids the argument of the independent DC trains. The catastrophic failure of a DC main bus breaker could lead to additional faults, that could not be cleared because there are no fault-rated disconnect devices in the main battery feeds. Determination of whether shutting the DC tie breaker with both batteries connected to the DC busses constitutes an USQ is considered to be Unresolved Item 50-280/98-201-09."

VIRGINIA POWER RESPONSE

Virginia Power agrees that shutting the DC tie breaker with both station batteries and all four battery chargers connected to the DC busses is not a desired configuration but was part of the original design as described in the FSAR. DR S-98-0719 was written against the DC bus cross-tie to document that the interim configuration of two batteries and four chargers was not covered by a calculation and would likely exceed the fault interrupting current of the DC bus. Virginia Power will revise the Maintenance Operating Procedures (MOP) for removal from service and return to service of station batteries, which currently allow the molded-case tie switch to be closed with both batteries connected to the bus. Until the MOPs are revised these procedures have been restricted from use. The new procedures will ensure that both station batteries and four chargers will not be tied together simultaneously.

Previous parallel operation of the cross-tied DC Bus sections connecting two batteries and four chargers was evaluated to ensure that this configuration was within the Surry

design basis. The original UFSAR allowed for parallel operation of the batteries and chargers as an abnormal line-up. During the cross-tied configuration with two 1500 amp-hour batteries and two 200 amp chargers operating in parallel, the EHB branch breakers (10,000 amp interrupting rating) in the DC Switchboard would not have been able to interrupt a fault in close proximity to the switchboard. However, this configuration was used only during cold/refueling shutdown conditions, independent DC trains were not required and the consequences of either a feeder fault or a bus fault were the same.

In 1988, the DC System was upgraded by implementation of DCP 85-32 and 85-34. The main station battery capacity was increased to 1800 amp-hours and the original DC Switchboard EHB branch breakers were replaced with Mark 75 HFB breakers (20,000 amp interrupting rating). Short-circuit calculation 14937.16-E-1 (later superceded by EE-0499) was performed to confirm that the interrupting capability of the DC branch breakers were adequate. However, it could be deduced from that short-circuit calculation, although acceptable for normal operation, that the DC branch breakers were unable to interrupt a fault near the DC Switchboard while in parallel operation. As a result, the portion of the UFSAR statement regarding parallel operation of the chargers and batteries was revised. The revised statement restricted the parallel operation of the bus sections to conditions where either battery is out of service for maintenance. The revised UFSAR statement did not preclude using the cross-tie breaker with two batteries connected as a means to allow one battery to be disconnected. Prolonged operation with the DC Bus sections in parallel with both batteries still connected was no longer permitted and procedures were changed to ensure that the step for closing the DC cross-tie was immediately followed by the steps to disconnect either of the batteries. This procedure structure minimized the time that the DC Bus was susceptible to excessive fault currents. During shutdown conditions, independent DC trains are required for AFW cross connect support of the operating unit. The loss of independence of the DC trains is allowed for 14 days during shutdown. Again, the consequences of either a feeder fault or a bus fault are the same.

During the execution of the cross-tie, the MOP requires the plant to be in Cold Shutdown or Refueling Shutdown. In accordance with Technical Specifications, two trains of shutdown cooling are required to be operable if fuel is in the reactor. If there is a loss of the DC buses, the vital buses would transfer to their alternate source without interruption of power to the vital loads. The emergency AC buses and running pumps would continue to be energized. Therefore, there would be no interruption of flow, flow indication or temperature indication for the RHR system. If DC power is lost, Loss of DC Power Procedure, ½-AP-10.06, would provide guidance for this type of event. This procedure would be used to provide guidance for manual breaker operation if there is a need to swap RHR or CC pumps etc. in order to maintain shutdown cooling. Similarly, this procedure would be used if the opposite unit requires the use of the AFW pump or Charging pump. Virginia Power concludes that the plant was within its design and licensing basis when the DC Bus Sections operated at refueling shutdowns with two batteries and four chargers in parallel for switching operations, therefore this plant configuration does not represent a USQ.

COMPLETION SCHEDULE

Maintenance Operating Procedures (MOP), for removal from service and return to service of station batteries, which currently allow the molded-case tie switch to be closed with both batteries connected to the bus, will be revised by October 1, 1998, which is prior to the next unit outage when they will be used.

ITEM NUMBER 50-280/98-201-10

FINDING TYPE IFI

DESCRIPTION DC Bus Tie Interlock (Section E1.2.2.2.2(b))

NRC ISSUE DISCUSSION

"The licensee is also reviewing the need to have an interlock on the tie switch between the two main DC buses in accordance with paragraph 4d of Section D of Safety Guide 6. This interlock is to prevent inadvertent operation of the tie switch. Licensee has written DR S-98-0661 to resolve the matter. The licensee's review of whether an interlock on the tie switch is needed is considered to be Inspector Followup Item 50-280/98-201-10."

VIRGINIA POWER RESPONSE

The manual DC bus tie breaker (molded case switch) does not have an interlock, in accordance with paragraph 4d of Section D of Safety Guide (SG) 6, to prevent inadvertent operation. As a result, DR S-98-0661 was written to document the design condition. Recommended initial corrective action, to tag the breaker to ensure administrative control, has been taken. The tag requires Shift Supervisor permission to operate the switch. The absence of an interlock is not considered an operability issue since the DC bus tie breaker is controlled by a procedure which contains adequate instructions and precautions. This switch is not normally in use. Virginia Power will perform an evaluation to document whether the existing DC cross-tie configuration needs to meet SG 6 requirements and if so, the evaluation will determine if modifications are warranted.

COMPLETION SCHEDULE

Virginia Power will perform an evaluation to document whether modifications are warranted to comply with SG 6 by August 1, 1998.

If modifications are required, Design Change Packages (DCP) will be developed to support implementation by the end of the Unit 2, 2000 refueling outage and by the end of the Unit 1, 2001 refueling outage.

ITEM NUMBER 50-280/98-201-11

FINDING TYPE IFI

DESCRIPTION Station Battery Calculation Discrepancies (Section E1.2.2.2.2(d))

NRC ISSUE DISCUSSION

"The team verified the sizing of the four station batteries for their two-hour load profiles in accordance with calculation EE-0046, "Surry 125 VDC Loading Analysis", Rev. 1. Calculation was acceptable with the following exceptions:

- Assumption 4 of calculation EE-0046 did not use the most conservative values for DC input currents to the inverters from the applicable test reports.
- Calculation did not consider the closing of the 4KV breaker for charging pump C during the first minute.
- Closing spring charging motors of 4KV breakers were assumed to draw 60 amps instead of the more conservative value of 80 amps
- Worst case load demand requirements of a LOCA with high-high CLS were not considered for the sizing of the station batteries.

The licensee initiated DR S-98-0606 to address the resolution of this topic, and performed an evaluation in accordance with IEEE 485 that demonstrated that the station batteries still had sufficient margin even when all above concerns were considered. However, the inverters became limited to a load of 9 KVA instead of their full load of 15 KVA due to the reduction in the battery design margin. The licensee's resolution of these discrepancies found in the calculations is considered Inspection Followup Item 50-280/98-201-11."

VIRGINIA POWER RESPONSE

DR S-98-0606 did not cover the items noted above, but was written to document errors in performing Addendum A to Calculation EE-0046. Response to DR S-98-0606 concluded that the station battery load analysis remains valid and the related equipment will perform their design function.

To address the items noted above, an informal sizing evaluation was performed in accordance with IEEE 485 during the A/E Inspection (in response to Item S-98-260) which concluded that the station batteries are acceptable. A subsequent addendum to Calculation EE-0046 for the new Unit 1 annunciator (Addendum 01B) took into account conservative values for inverter input current, included a first minute breaker operation for the "C" charging pump, incorporated a conservative value for spring charging motor inrush, and included other conservatisms (i.e., added random load believed to bound any worst case loading scenario). This Addendum provides confidence that the design margins associated with the station batteries bound the concerns noted above.

DC Loading Calculation EE-0046 will be revised to formally account for the discrepancies noted above.

COMPLETION SCHEDULE

Calculation EE-0046 will be revised by March 30, 1999.

ITEM NUMBER 50-280/98-201-12

FINDING TYPE IFI

DESCRIPTION EDG Battery Design Margin (Section E1.2.2.2.2(e))

NRC ISSUE DISCUSSION

"The team reviewed calculation 14937.28, Revision 2. The calculation assumed a successful EDG start at the end of the two-hour load profile and at least one unsuccessful start in the first minute. The team identified discrepancies with the assumption and other design inputs to the calculation. The licensee issued DR S-97-0677 to review the following three concerns:

- Calculation should provide the worst-case battery loading by assuming at least two unsuccessful starts in the first minute.
- The starting currents for some DC motors, in the EDG starting circuits, may be partially concurrent with the current drawn by the EDG field flash circuitry.
- The second start attempt in the first minute invokes two redundant starting circuits (DC auxiliary motors and control circuitry) instead of one, thereby almost doubling the load demand previously assumed. Also, the licensee committed to verify whether some additional continuous loads may be added to the battery load profile.

Each concern can cause the battery load current to increase, thus reducing previous battery loading margins. The licensee did not reevaluate the sizing of the EDG batteries but felt that there was no operability concern because of the available design margin with the EDG batteries. The licensee's review of the identified discrepancies on the battery design margin is considered to be Inspection Followup Item 50-280/98-201-12."

VIRGINIA POWER RESPONSE

An operability review was performed for the issues listed above per DR S-98-0677 response. This review concluded that adequate margin is available in the EDG battery sizing such that the discrepancies identified will not reduce the available margin so as to effect battery operability. The specific discrepancies identified are considered enhancements to the existing calculations in that the conclusions of the calculation will not change. Calculation 14937.28 for the EDG Battery two-hour load profile will be revised to incorporate the concerns listed above. In addition, calculation 14937.75, for the EDG Battery four-hour load profile, will be reviewed to determine if similar discrepancies exist, and will be revised accordingly.

COMPLETION SCHEDULE

Calculations 14937.28 and 14937.75 will be revised by December 16, 1998.

ITEM NUMBER 50-280/98-201-13

FINDING TYPE IFI

DESCRIPTION DC Fault Contribution (Section E1.2.2.2.2(f))

NRC ISSUE DISCUSSION

"The team reviewed calculation EE-0499, "DC Vital Bus Short Circuit Current", Rev. 1, and determined that all DC buses and associated cabling for the main 125 VDC system were conservatively sized for the available short circuit currents. Double-pole breakers provide the correct overload and fault protection for the DC system distribution circuits, and the correct sizing of protective devices ensures the requisite selective coordination between protective devices in series when applicable.

A similar analysis did not exist to determine the available fault currents to the components and distribution circuitry supplied by the EDG batteries. Licensee wrote DR S-98-0677 to review this concern. Review of DR S-98-0677 is considered to be Inspection Followup Item 50-280/98-201-13."

VIRGINIA POWER RESPONSE

The referenced DR is associated with EDG battery duty cycle. No DR has been issued regarding available fault current since there has been no condition identified in which available fault current exceeds component design. Virginia Power will prepare a new calculation to determine the available fault currents to the components and distribution circuitry supplied by the EDG batteries. Resolution of any identified improperly sized components will be handled by the corrective action process.

COMPLETION SCHEDULE

An EDG Battery short-circuit calculation will be completed by December 1, 1998.

ITEM NUMBER 50-280/98-201-14

FINDING TYPE IFI

DESCRIPTION DC Load Flow/Voltage Drop (Section E1.2.2.2.2(g))

NRC ISSUE DISCUSSION

"The team reviewed calculation EE-0046, "Surry 125 VDC Loading Analysis", Revision 1 in regard to voltage available to DC components. The licensee did not calculate the actual voltage at DC devices or components but at the ends of the field cables exiting the 125 VDC switchboards and panels. In many cases, a field cable terminates in an enclosure or rack in which the actual end component can be found but in several other cases additional cables or wiring are traversed to get to the actual end components. These additional cables or wiring runs cause additional voltage drops possibly hindering the operability of a given end component. The licensee wrote a DR S-98-0649 to evaluate all affected circuits and determine the effects of any additional voltage drops on the operability of end components. Preliminary calculations performed by licensee during inspection did not indicate a problem with any device being unable to perform its safety function due to low voltage at it input terminals. Additionally, this calculation showed only one inter-rack connector (twelve-foot, 750 MCM cable) when in fact there are two such connectors which for battery 1A will cause an another .24 VDC drop in battery terminal voltage at the end of a battery discharge. The licensee wrote DR S-98-0674 to document and evaluate the impact of the additional cable. These two items are considered to be Inspection Followup Item 50-280/98-201-14."

VIRGINIA POWER RESPONSE

The initial design of the Surry DC system did not include calculations of the actual voltage at the end DC devices. Informal evaluations, performed in response to DR S-98-0649, have not identified any equipment which cannot perform its safety function due to minimum voltage concerns. Worst case bounding conditions were assumed and the voltage was determined to be adequate. For this reason, all affected equipment has been determined to be able to perform it's intended safety function for worst case DC voltage levels. In order to ensure end components are receiving acceptable voltage, new calculations will be performed for all affected DC circuits. Any component determined to be detrimentally affected by the actual voltage seen at the device, will be analyzed per the corrective action process.

In addition, although the calculation shows only one inter-rack connector for battery 1A, when in fact there are two such connectors, the evaluation in response to DR S-98-0674 has determined that this drop in battery terminal voltage is bounded by the existing design basis and is not an operability concern. The revision of calculation Electrical Engineering EE-0046, noted in response to item 50-280/98-201-11 above, will incorporate the existence of two inter-rack connectors for station battery 1A.

COMPLETION SCHEDULE

Calculation EE-0046 will be revised by March 30, 1999.

The development of a new DC System transient model and calculation encompassing end components will be complete by December 16, 1999.

ITEM NUMBER 50-280/98-201-15

FINDING TYPE IFI

DESCRIPTION Adequate DC Component Voltage (Section E1.2.2.2.2(g))

NRC ISSUE DISCUSSION

"A similar analysis to Item 50-280/98-201-14 does not exist to determine whether the DC components supplied by the EDG batteries have the requisite voltage at their input terminals. Licensee is to review this concern under DR S-98-0677. This is considered to be Inspection Followup Item 50-280/98-201-15."

VIRGINIA POWER RESPONSE

The referenced DR is associated with EDG battery duty cycle. No DR has been issued regarding adequate voltage at end devices since there has been no condition identified in which available fault current exceeds component design.

Specific design calculations and testing have not been completed to assure available voltages meet equipment requirements. Successful equipment function and functional testing indicate that available voltage operates the equipment properly. Additional calculations, which have been recommended to increase our level of confidence in our design, will be performed by Virginia Power.

In order to ensure end components are receiving acceptable voltage, a new analysis will be performed for components supplied by the EDG Batteries. Any component determined to be detrimentally effected by the actual voltage seen at the end device will be analyzed per the corrective action process.

COMPLETION SCHEDULE

The development of a new analysis for voltage drops for EDG DC loads will be complete by December 16, 1999.

ITEM NUMBER 50-280/98-201-16

FINDING TYPE IFI

DESCRIPTION DC Load Control (Section E1.2.2.2.2(h))

NRC ISSUE DISCUSSION

"The team reviewed the methodology for documenting load changes for both AC and DC buses, and some recent DCPs (design change packages) that had actual load changes in them. Electrical load changes are initially recorded in a computer printout of the database of SELL (Station Electrical Load List) and then incorporated in the next update of that database. Several concerns with this process were identified by the team during the inspection. The licensee agreed with the following team's concerns and will evaluate the process under DR S-98-0726:

- Load changes at lower buses are not always reflected in total loading of upstream buses in between updates of the SELL data base.
- Procedure STD-EEN-0026,"Guidelines for Electrical System Analysis," Revision 5, Step 6.1.2 requires that new loads be inputted to the electrical data base four weeks prior to issuing a draft DCP. Presently only the SELL printout is marked up prior to issuance of a DCP with new load changes inputted into the electrical database annually.
- No one person is accountable for electrical load changes and has ownership responsibility for incorporating them in SELL database.
- The time between both calculation revisions and SELL data base updates (5 to 7 years for some critical calculations) is too long with only the marked up SELL printout reflecting the true status of the loading of electrical buses in the interim.
- Licensee reviewed 30 DCPs in response to a question by the team and found that 7 out of the 30 DCPs had not properly incorporated load changes into the marked up printout of the SELL database. These errors probably would have been inputted into the SELL database at the next annual update. The total error on DC bus 2B, the bus most impacted, was 4 amps. The licensee momentarily lost control of the loading on its DC buses because electrical load changes were improperly tracked.

This item was identified as Inspection Followup Item 50-280/98-201-16."

VIRGINIA POWER RESPONSE

Virginia Powers' immediate response was to verify the existing DC bus condition, as noted above, was acceptable. We have reconciled the 4 amp difference and have shown that adequate battery margin exists for the discrepancies identified. In addition to the DCPs screened by the NRC Inspector, Engineering has reviewed all DCPs with DC electrical changes for affect on the SELL. Only minor discrepancies were identified. For the errors that were found, Engineering has incorporated the corrections into the appropriate SELL documents.

The procedures governing the control of the SELL will be revised to strengthen the requirement to reflect load changes at lower buses in total loading of upstream buses, in between updates of the SELL data base. In addition, these procedures will be revised to include an appropriate time frame for issuance of a revised SELL to be consistent with the current Design Change Process. Procedures will also be changed to assure changes which may affect values in other programs are applied appropriately.

The anticipated procedures affected will be NDCM STD-EEN-0026, "Electrical Systems Analysis," and Implementing Procedure EE-010, "Update, Review and Approval of the GDC-17 and SELL."

Engineering will give SELL training, encompassing the revised procedures, to the Electrical Engineering staffs both at Innsbrook and at Surry. The responsibilities of the individuals required to maintain the SELL database will be emphasized.

COMPLETION SCHEDULE

The required changes to procedures, NDCM STD-EEN-0026, "Electrical Systems Analysis" and Electrical Engineering Implementing Procedure EE-010 "Update, Review and Approval of the GDC-17 and SELL" will be completed by December 15, 1998.

Electrical Engineering training as described above will be completed by March 15, 1999.

ITEM NUMBER 50-280/98-201-17

FINDING TYPE IFI

DESCRIPTION Battery Surveillance Test (Section E1.2.2.2.2(l))

NRC ISSUE DISCUSSION

"The performance tests for the station and EDG batteries were not performed in accordance with IEEE 450-1980 which licensee imposed on itself. Licensee would terminate the performance tests after a specified time not at the end voltage of 1.75 volts per cell per IEEE 450. This caused the battery capacity to be recorded at too low of a value and interfered with accurate trending of battery capacity. IEEE 450 invokes the performance of a service test each year once battery capacity drops at least 10 percent from the last test. Early termination of the performance tests delays the invoking of this increased monitoring. Licensee was aware of this deviation from IEEE 450 and had initiated an update of the involved procedures. To date only the performance tests for Unit 2 station and EDG batteries have been revised. If the capacity is less than 90 percent, the procedure requires that a deviation report be written, instead of the performance of a service test each year as required by IEEE 450. As a further corrective action for trending performance tests, the licensee will extrapolate the data of the last discharge test for each station battery to determine the actual capacity if the test had been completed per IEEE 450. This item was identified as Inspection Followup Item 50-280/98-201-17."

VIRGINIA POWER RESPONSE

The three performance test procedures 0/1/2-EPT-0106-08 for the EDG batteries have been revised to conform with IEEE 450-1980. The procedures for the Station batteries will be revised accordingly.

The data from the last discharge test has been extrapolated for each Station battery and actual capacity was acceptable based on the acceptance criteria of IEEE 450.

In addition, the battery capacity trends have been completed and are being maintained for the EDG batteries. Trending for the Station batteries is being done and will be made consistent with the methods for EDG trending in conjunction with procedure development.

COMPLETION SCHEDULE

Procedure revisions and capacity trending will be in place for Station batteries by September 30, 1998.

ITEM NUMBER 50-280/98-201-18

FINDING TYPE IFI

DESCRIPTION Fuse Control (Section E1.2.2.2.2(j))

NRC ISSUE DISCUSSION

"The licensee has developed a fuse control program that consists of comprehensive fuse lists and procedures for replacement of fuses. The fuse lists were detailed tabulations of the safety-related fuses in power and instrument circuits depicting inherent characteristics for identification and sizing. The licensee estimated that 90 percent of the fuses in the fuse lists have been both design and field verified. An attempt has been made to incorporate all the safety-related fuses in the fuse lists but there are outliers for which the licensee was unable to estimate the number during the inspection. Deviation reports have been issued indicating that the fuses installed in some non-safety-related circuits were not correct. The team sampled installed fuses and the data in the fuse lists and found the fuses to be adequately sized and the supporting data to be accurate. Recently the licensee experienced a failure of a replacement fuse because it did not have a time overcurrent plot similar to that of original fuse. The licensee realizes that its Item Equivalency Evaluation Review (IEER) process for fuses needs to be upgraded to include similar overcurrent plots as a further qualifying item in the replacement of fuses. This item was identified as Inspector Followup Item 50-280/98-201-18."

VIRGINIA POWER RESPONSE

The specific discrepancies in fuse type or size have been corrected under the Virginia Power corrective action program. The fuse control program referenced was developed after the plant was complete and in operation. The method of capturing the 'as built' configuration was to take the specified fuse information from existing drawings. When this method could not be applied, due to missing information, field walkdowns collected information from the installed fuses. This process has continued and information is added as it is identified. The referenced DRs are examples of this process in action. The same DR review demonstrated that there have been very few problems with incorrect fuses installed in the field. For these reasons, Virginia Power will continue to complete the fuse lists on an as-needed basis.

The "90% of the fuses on the fuse list" that were stated as "verified" during the inspection were intended to reflect the process identified above. Virginia Power has not had reason to question the original specification of fuses or changes to fuses made under our design control program, therefore, no specific design basis reconstitution for fuses has been initiated.

An investigation into the replacement fuse mentioned above was performed. Virginia Power has researched the Item Equivalency Evaluation Review (IEER) electronic database and determined that there were no IEER's performed at Surry Power Station

for a replacement fuse. The fuse mentioned above was determined to be a replacement fuse(s), which through personnel error, was not processed through the formal item equivalency evaluation process prior to being issued out of inventory and installed into plant equipment.

A Design Reference Procedure (DRP) exist for fuses, which specifically denotes the manufacturer/model of the fuse to be used and the specific plant location(s) where installation of the fuse is acceptable. Any suggested fuse, for either safety related, NSQ, or non-safety related applications that is not an identical (like for like) replacement is required to have the appropriate technical reviews performed and documented either through a Design Change Package (DCP) or an IEER prior to installation.

VPAP-0708, "Item Equivalency Evaluation" requires that all the critical characteristics for design be documented for the original and recommended substitute. If there are any differences, a technical explanation for acceptability must be provided and documented in the IEER or may be included as an attachment in the form of an ET (Engineering Transmittal) provided by engineering for added technical justification. A critical design characteristic for fuses is the time current curve. An IEER would consider, for comparison purposes, the time current curves as the primary, if not the most critical of the design characteristics. An IEER requires an independent design review, which would include the comparison of the curves.

Virginia Power has determined that the procedure for the Item Equivalency Evaluation, VPAP-0708, will not require a revision. Virginia Power will review the maintenance work management process for ensuring that non-identical replacement fuses are processed through this IEER program and will provided enhancements to the process if required.

Virginia Power will train appropriate personnel on the IEER program as it relates to non-identical fuse replacements.

COMPLETION SCHEDULE

Virginia Power will review the process for ensuring that non-identical replacement fuses are processed through this IEER program and will provide enhancements to the IEER and maintenance work management process, if required, by December 15, 1998.

Virginia Power will train appropriate personnel on the IEER program as it relates to non-identical fuse replacements by March 15, 1999.

ITEM NUMBER 50-280/98-201-19

FINDING TYPE IFI

DESCRIPTION RS System Flow (Section E1.3.1.2(a))

NRC ISSUE DISCUSSION

"The team evaluated the following calculations to evaluate the capability of the RS system to fulfill its safety function:

- 01039.6210-US-(B)-107, "Containment LOCA Analysis for Core Uprate," Rev. 0
- 01039.6210-US-(B)-106, "LOCTIC LOCA Input Parameter Values for Core Uprating," Rev. 0
- ME-0405, "Minimum Required TDH for Inside Recirculation Spray (IRS) Pump for Core Uprate - Units 1 & 2," Rev. 0
- ME-0418, "Minimum Required TDH for Outside Recirculation Spray (ORS) Pump for Core Uprate - Units 1 & 2," Rev. 0

In the analysis, a total RS flow of 5700 gpm was considered of which 2700 gpm was contributed by the IRS pumps and 3000 gpm was contributed by the ORS pumps.

The review identified that calculation ME-0405 did not take into account flow diversion from the Unit 1 IRS pumps which would not be available to the RS spray headers. The team and licensee identified the following diversion paths:

- Through 3/8" vents on the RS side of the Recirculation Spray Coolers (1-RS-E-1A & 1B) with no isolation valves.
- Through ½" instrument tubing on the RS side of the Recirculation Spray Coolers with partially (1 ½ turns) open manual valves 1-RS-70 & 72 and fully open instrument valves 1-RS-71 & 73 downstream of level switches 1-RS-LS-152 A & B.
- Through ½" fully open drain valves 1-RS-84 & 85 downstream of which are 1/8" orifices.

Similar flow diversion paths were also identified with the Unit 2 IRS pumps:

- Through 3/8" vents on the RS side of the Recirculation Spray Coolers (2-RS-E-1A & 1B) with no isolation valves.
- Through ½" instrument tubing on the RS side of the Recirculation Spray Coolers with partially (1 ½ turns) open manual valves 2-RS-18 & 19 and fully open instrument valves 2-RS-43 & 57 downstream of level switches 2-RS-LS-252 A & B.

The licensee performed preliminary analyses, ET CME-98-0013, Rev. 2, ET NAF-980038, Rev. 1, and safety evaluation 98-0033, which determined that the total flow diverted for the IRS pumps in Unit 1 and Unit 2 was about 47 and 44 gpm respectively. The analyses also determined that all IRS pumps in both units would provide more than the required 2700 gpm, the least (Unit 1, Train A) being 2738 gpm and the most (Unit 2, Train B) being 3029 gpm, to the recirculation spray headers after allowing for the losses

through the above mentioned unidentified flow paths. The inspection team concurred with the conclusions of the analyses.

The review also identified that calculation ME-0418 did not take into account flow diversion from the Unit 1 ORS pumps which would not be available to the RS spray headers. The team and licensee identified the following diversion paths:

- Through 3/8" vents on the RS side of the Recirculation Spray Coolers (1-RS-E-1C & 1D) with no isolation valves.
- Through ½" instrument tubing on the RS side of the Recirculation Spray Coolers with partially (1 ½ turns) open manual valves 1-RS-74 & 76 and fully open instrument valves 1-RS-75 & 77 downstream of level switches 1-RS-LS-152 C & D.
- Through ½" fully open drain valves 1-RS-86 & 87 downstream of which are 1/8" orifices.

Similarly, the calculation ME-0418 did not take into account the flow diversion paths for the ORS pumps in Unit 2.

- Drain lines routed to the emergency sump and located downstream of check valves, 2-RS-11 and 17, with spectacle flanges 2-RS-FNG-70A & 71A. These drain lines do not indicate any line number identification or pipe sizes on the drawing.
- Through 3/8" vents on the RS side of the Recirculation Spray Coolers (2-RS-E-1C and 1D) with no isolation valves.
- Through ½" instrument tubing on the RS side of the Recirculation Spray Coolers with partially (1 ½ turns) open manual valves 2-RS-20 & 21 and fully open instrument valves 2-RS-64 & 65 downstream of level switches 2-RS-LS-252 C & D.

The licensee's preliminary analyses, ET CME-98-0013, Rev. 2, ET NAF-980038, Rev. 1, and safety evaluation 98-0033, in this case determined that the total flow diverted for the ORS pumps in Unit 1 and Unit 2 was about 47 and 87 gpm respectively. The analyses further determined that all ORS pumps in both units provide less than the required 3000 gpm, the worst (Unit 2, Train B) being 2958 gpm and the best (Unit 1, Train B) being 2998 gpm, to the recirculation spray headers after taking into account the losses through the above mentioned unidentified flow paths.

However, for either A or B Train, the IRS pump flows have enough margins to cover the reduced flow from both ORS pumps, such that the total required flow of 5700 gpm for any RS train used in the containment analysis was not affected. The worst case IRS and ORS combination was Unit 1, Train A, which would deliver 5721 gpm to the spray headers after allowing for the losses through the unidentified flow paths in both the IRS and ORS pumps. Therefore, the preliminary analyses concluded that the acceptance criteria for the containment analyses of record would continue to be met even with the loss of flow from the unidentified flow paths for both Surry Units.

Safety evaluation 98-0033 was prepared to revise the UFSAR Section 6.3 to discuss the impact of the diverted flow through the vents and drains, and that the reduction in

the ORS flow requirements to the spray headers would not affect the total RS flow values used in the containment analysis for core uprate. Also, licensee issued DR S-98-0673 to take corrective actions, including alternatives to minimize flow through the unidentified flow paths. Licensee's long term resolution to this issue is considered an Inspection Followup Item 50-280/98-201-19."

VIRGINIA POWER RESPONSE

The following flowpaths, that divert flow from the Recirculation Spray System (RS) headers, were determined to be unaccounted for in previous RS system flow analysis:

- RS Heat Exchangers (RSHX) shell level switch vent/drains that are maintained open
- Drain line downstream of Outside RS inside Containment Isolation Valve
- Shell vents on the RSHXs

Engineering Transmittals CME 98-0013, Rev. 2, and NAF 98-0038, Rev. 0, were prepared to provide technical assurance of the ability of the RS system to deliver required flows through the combination of both the inside and outside RS system spray arrays in order to effect design basis containment depressurization, while accounting for system flows through vents and drains that are currently not included in the RS system design basis flow calculations. The analysis concluded that the RS system continues to meet the acceptance criteria for the containment analysis of record.

The need for each of these flowpaths will be evaluated and, if not necessary, it will be deleted. For the flowpaths that can be eliminated, a Design Change Package (DCP) and/or procedure revisions will be prepared. The changes will be implemented by the end of the 1998 RFO for Unit 1 and the 1999 RFO for Unit 2. System flow calculations will be updated by the implementation of the DCPs to include those flowpaths that could not be eliminated.

In addition, a review of the Surry Containment Spray system will be performed to ensure that unanalyzed diversion flowpaths do not exist. This review will be completed by December 15, 1998.

COMPLETION SCHEDULE

Design Changes will be implemented to eliminate non-needed flow paths for the RS system by the end of the 1998 refueling outage for Unit 1 and 1999 refueling outage for Unit 2. System flow calculations will be updated by the implementation of the DCPs to include those flowpaths that could not be eliminated.

The Containment Spray System review will be completed by December 15, 1998.

ITEM NUMBER 50-280/98-201-20

FINDING TYPE IFI

DESCRIPTION Unqualified Coatings (Section E1.3.1.2(c))

NRC ISSUE DISCUSSION

"The team, however, noted that the coating (paint) systems on the RCP motors were not qualified to withstand the post accident conditions in the containment. Their delamination during accident and subsequent migration inside containment to the containment emergency sump could result in the blockage of the fine-mesh screens surrounding the sump. This in turn would impede the flow of the spray water. Thus, adversely affecting the NPSH of the RS and LHSI pumps that take suction from this sump in the long term recirculation mode after a LOCA.

A preliminary evaluation performed by the licensee indicated that due to the tortuous path and the low velocity (SWEC calculation 14937.30-US(B)-075, "Transport of Paint Chips to the Containment Sump Screens," Rev. 0, December 12, 1988) at which the failed coatings from the RCP motors would be transported, operability of the RS and LHSI pumps would not be affected.

However, the licensee has not yet identified all the unqualified coatings inside containment that could potentially fail due to irradiation at the post accident environmental conditions inside containment. Also, the calculation 14937.30-US(B)-075 did not address the running of the LHSI pumps and the resultant effect on the velocity, zone of influence, and the quantity of failed coatings in suspension in the water. Therefore, the licensee has initiated a PPR 98-022 and DR S-98-0667 to determine all the unqualified coatings inside containment and evaluate the impact of their delamination and migration to the containment sump screens and eventual blockage of the containment sump screens. Licensee's evaluation of the effect from unqualified coatings on the containment sump screens is considered an Inspection Followup Item 50-280/98-201-20."

VIRGINIA POWER RESPONSE

The acceptability of coatings in containment applied in accordance with the original construction specification is based on the original evaluations for selection and application of coatings. A degree of testing and assessment of the original coatings was conducted that documented the suitability of application for an accident environment. The analysis performed employed methods that were considered to be state of the art. Controlled documents were employed to direct the application of coatings in containment and have been periodically revised to incorporate DBA qualified coatings that met adopted industry standards. Based on Virginia Power's previous assessment of coatings inside containment, the operability of the containment sump is currently not in question.

An effort has commenced in which unqualified coatings and other debris sources (herein now referred to as debris) inside containment will be identified. This information will be evaluated to determine the affect of debris migration and potential blocking of the containment emergency sump. The adverse affects of sump blockage on NPSH of the RS and LHSI pumps that take suction from the sump will also be evaluated.

Virginia Power has developed a preliminary Scope of Work that addresses the major elements and parameters to be investigated as discussed in the inspection report. The objectives of this investigation have been divided into two major tasks described below. These tasks will be implemented in distinct phases.

Task 1: Perform a coating condition assessment - This task will determine the qualification status of coating inside containment. This will also provide the initial data base required to initiate the unqualified coating log that tracks the status of unqualified coatings inside containment. This task will provide a basis for a program to be developed to evaluate coatings on replacement equipment and components for use inside containment.

Task 2: Analysis and assessment of available NPSH margin - This task will estimate the amount of coating surface area that can fail by evaluating the total debris (insulation, coating and other) blockage and resulting pressure drop compared to the available NPSH margin. Also, zones of influence for determining the quantity of debris that migrates to the emergency sump will be identified and analysis of debris transport and NPSH will be performed.

The Scope of Work and Schedule are listed in this response as preliminary. This is due to the expected issuance of an NRC Generic Letter addressing unqualified coatings. Virginia Power will follow the action plan outlined above until such time that a Generic Letter is issued. At this point, Virginia Power will review the requirements of the Generic Letter and assess the need to modify our action plan. Revisions to our scope and schedule may be in order to join an integrated industry review and response. Any changes to the above action plan and schedule, due to the issuance of a Generic Letter, will be promptly communicated to the NRC.

COMPLETION SCHEDULE

The preliminary schedule for the completion of Tasks 1 and 2 is January 31, 2001.

ATTACHMENT 2

PROGRAM ENHANCEMENTS

PROGRAM ENHANCEMENTS

1). Corrective Action

NRC Observations related to the Corrective Action Process

In the Executive Summary to NRC Inspection Report Nos. 50-280/98-201 and 50-281/98-201, the NRC made the following observation:

> "The licensee failed to effectively resolve issues identified through their engineering analyses and self-assessments. These examples included: failure to resolve the acceptability of AC voltage which was calculated to be less than the design value of 480 volts at the bus; failure to perform the recommended breaker-to-breaker or breaker-to-fuse coordination evaluations; and some corrective actions resulting from the licensee's Electrical Distribution Safety Functional Assessment (EDSFA)."

Virginia Power Response

Corrective actions for Virginia Power are guided by our administrative procedures VPAP-1501, "Deviation Reports" and VPAP-1601, "Corrective Action." These administrative guidelines lay the foundation for early identification of issues and the complete and thorough resolution of identified concerns. Station Management has taken an active role in ensuring that deviation reports (DRs) and commitment tracking system (CTS) items are properly and thoroughly resolved. Although, Virginia Power has a strong program, it is recognized that improvements to the programs can be made to ensure corrective actions are effectively implemented.

Virginia Power recognizes that recommendations and follow-up actions identified in Engineering documents such as calculations, technical reports, and Engineering Transmittals (ETs) have not always been clearly translated into completed actions or tracked to resolution. Engineering is evaluating the causes and possible remedies for this situation. Program weaknesses and human error have contributed to deficiencies in the implementation of these programs. This comprehensive evaluation will provide insight into actions needed to prevent a repeat of the problems identified during the inspection effort. For example, issues will be tracked to resolution by providing appropriate tracking mechanisms, engineers will be trained to provide closure on open issues, and procedural guidance will be added to assure required corrective actions are always included in the established corrective action program. Revisions will then be made to applicable procedures and standards by August 31, 1998 to ensure that required actions are identified, tracked and fully implemented. This evaluation will address all Engineering procedures and standards for preparing calculations, technical reports, and ETs. Training will then be provided to all appropriate Engineering personnel by September 30, 1998 to ensure the programmatic improvements are

Additionally, Engineering's Potential Problem Reporting (PPR) process will be reviewed for possible enhancements. The PPR process is used to evaluate complex technical issues to determine whether a deviating condition exists. The PPR process ties to the existing company DR process have been strengthened in recent months to ensure problems are quickly and thoroughly identified and then fed into the Station's existing corrective action programs.

As Virginia Power noted during the inspection, the EDSFA/EDSFI identified a number of Engineering actions which have not yet been completed. As a result, a Root Cause Evaluation (RCE) is being conducted to determine what open issues remain, why the issues were not properly completed and identify an action plan for resolution of the open issues. This root cause evaluation is reviewing all of the action items from EDSFA, not just the open items, to ensure that actions taken or planned are acceptable. The results of the RCE will be presented to management for approval of recommended corrective actions by July 31, 1998. Engineering is developing a new work management tool that will support the resolution of corrective actions. This new "Task Tracking" program will provide a comprehensive tracking system of the Engineering work load to provide management with information to allocate resources to support effective and timely completion of corrective action work items.

2). Configuration Management

NRC Observations related to Configuration Management

In the May 11, 1998 cover letter transmitting NRC Inspection Report Nos. 50-280/98-201 and 50-281/98-201, the NRC made the following observation:

> "Based on the number of discrepancies found in your UFSAR and your design basis documents (DBDs), your additional attention to improve the quality of these documents appeared warranted."

In the Executive Summary to NRC Inspection Report Nos. 50-280/98-201 and 50-281/98-201, the NRC made the following observation:

> "Other discrepancies included instances where the surveillance procedures were not consistent with design bases, differences between the as-built configuration and the system design as shown on the drawing or the UFSAR, and various calculation deficiencies. The team had some difficulties in obtaining the most recent calculations because the licensee's calculation index system did not distinguish between active and inactive calculations. The team also identified a number of UFSAR and DBD discrepancies."

Virginia Power Response

Virginia Power agrees that additional attention to improve the quality of the Updated Final Safety Analysis Report (UFSAR) and Design Basis Documents (DBD) is warranted and that discrepancies exist among those various documents. Actions to identify and resolve those discrepancies have been underway since April 1997 when Virginia Power established a new organization within its Nuclear Business Unit to address the concern. The new organization, entitled the Integrated Configuration Management Project, has as its primary goal the effective management of ongoing programs intended to improve design and licensing bases documentation, and to demonstrate compliance with those bases in the operation of Surry Power Station.

The overall Project approach is to complete the verification and validation of plant configurations, operations documents, the UFSAR, and Improved Technical Specifications (ITS) on a system-by-system basis, following the issuance of individual system Design Basis Documents. Integration Review teams, lead by project engineers and comprised of engineering, operations, and licensing personnel, conduct comprehensive reviews utilizing a rigorous methodology to demonstrate that operations at Surry complies with its design and licensing bases, and to initiate change documents as required.

The Project was initially described in our February 7, 1997 response to NRC's October 9, 1996 10CFR50.54(f) request for information regarding the adequacy and availability of design basis information. Further details were provided in our May 23, 1997 letter to

the NRC in which the scope and methodology of an updated FSAR review and validation plan were provided to meet NRC's expectations as expressed in the October 18, 1996 Enforcement Policy revision.

The Project represents a substantial undertaking by Virginia Power. Upon management approval of the Project, substantial efforts were required to mobilize the new organization. These effects included staffing, acquiring physical facilities and computer resources, and developing the detailed methodology, procedures, and computer software necessary to support various Project tasks. Project staffing is roughly 70 personnel, including more than 50 full-time project staff and an equivalent of 20 full-time technical staff drawn from within the Virginia Power Nuclear organization to support the various integrated review teams.

During the inspection, NRC observed instances where the surveillance procedures were not consistent with the design bases, and differences were identified between the as-built configuration and the system design as shown in a drawing or in the UFSAR. The NRC also identified a number of other UFSAR and DBD discrepancies. It is Virginia Power's intent to address and correct each discrepancy identified by the NRC in a timely manner. Each discrepancy has been entered into the Project's tracking database and will be resolved during the integrated review for the affected system in accordance with the Project's published schedule.

In summary, Virginia Power has already focused appropriate attention and resources on the concern expressed in the NRC's May 11, 1998 inspection report. Based on Project results to date, the Integration Reviews are demonstrating the adequacy of design and licensing bases information on a system basis, and initiating corrective action, when required. However, to determine whether any enhancements to existing processes are appropriate, those review processes will be assessed in light of the specific observations described in NRC Inspection Report Nos. 50-280/98-201 and 50-281/98-201 regarding design and licensing bases documents. That assessment will be completed by August 31, 1998.

3). Calculation Deficiencies

NRC Observations related to Calculation Deficiencies

In the Executive Summary to NRC Inspection Report Nos. 50-280/98-201 and 50-281/98-201, the NRC made the following observations:

> "The team had some difficulties in obtaining the most recent calculations because the licensee's calculation index system did not distinguish between active and inactive calculations."

> "The licensee did not have a robust amount of electrical calculations to support the AC and DC system design basis. The following were unavailable: cable ampacity calculation to verify cable sizing; calculations to demonstrate that the penetration circuits were within design limits; analyses which justified the sizing of the DC penetrations; analyses which examined the fault currents to the DC components and their distribution circuitry; and analyses which showed that the DC voltage at the component level was adequate to operate the devices."

Virginia Power Response

Virginia Power has high confidence that plant systems are conservatively designed with respect to plant design basis. The Design Basis Document (DBD) program, which has been in process since 1989, has completed identification of critical calculations for electrical systems and performed an assessment to determine the adequacy of those calculations to support the electrical system design. Where necessary, critical calculations were reconstituted to ensure that the minimum set of design information exists to demonstrate that system functional requirements are met. DBD open items were generated to further upgrade the body of electrical calculations to enhance the availability of design basis information. The DBD program contains an ongoing element to identify and resolve open issues related to electrical calculations. Through planned and ongoing efforts, Virginia Power will address additional calculations, which have been recommended to increase our level of confidence in our design. Additional measures to control documentation of which calculations are active will be pursued to reduce the likelihood of an error in maintaining our program.

Calculation Control – An enhancement to the Virginia Power calculation control program has been implemented which reinforces the requirement that all users determine which calculations, or portions of calculations are active prior to their reference or use. A study is being conducted to determine if any further changes to this program are needed that would enhance the users ability to determine the status of calculations. The study will be completed and any changes to the program will be incorporated by January 31, 1999.

Electrical Calculations – The design of the Surry Power Station was such that detailed component level calculations were not documented, in some cases, during original design. To upgrade the calculation availability for the electrical systems, the following calculations will be performed:

1. Cable ampacity calculations to verify cable sizing will be completed by December 1, 1998.
2. Calculations to demonstrate that the penetration circuits are within design limits will be completed by December 1, 1998.
3. Analyses to justify the sizing of the DC penetrations will be completed by December 31, 1998.
4. Analyses to examine the fault currents to the DC components and their distribution circuitry will be completed per the response to Item 50-280/98-201-13.
5. Analyses to show that the DC voltage, at the component level, is adequate to operate the devices will be completed per the responses to Items 50-280/98-201-14 & 15.

ATTACHMENT 3

SUMMARY OF COMMITMENTS

SUMMARY OF COMMITMENTS

The following commitments are made in response to the findings identified in Inspection Report Nos. 50-280/98-201 and 50-281/98-201.

1. ITEM NUMBER 50-280/98-201-02

   DESCRIPTION Error in Calculation SM-1047, "Reactor Cavity Water Holdup"

   COMMITMENT The UFSAR changes associated with the Safety Injection System NPSH analysis penalties are to be incorporated into the UFSAR by August 31, 1998.

2. ITEM NUMBER 50-281/98-201-03

   DESCRIPTION Unit 2 LHSI Pump Minimum Flow

   COMMITMENT A modification package will be implemented during the 1999 Refueling Outage for Unit 2 and the 2000 Refueling Outage for Unit 1 to resolve the susceptibility of the LHSI Pumps to interaction during periods when the pumps are operated in parallel on the recirculation flowpath.

   Virginia Power's evaluations performed in response to NRC IEB 88-04 will be reviewed to ensure that there are no other invalid assumptions regarding pumps that are susceptible to potentially harmful interactions. This review will be completed by October 1, 1998 and a revised response submitted, if necessary.

3. ITEM NUMBER 50-280/98-201-04

   DESCRIPTION Motor Thermal Overload for 1-S1-P-1B

   COMMITMENT Calculation EE-0497 will be revised by November 15, 1998.

   The Design Change Package (DCP) to install the new LTD/INST trip settings by modifying or replacing the breaker, as required, associated with the 1-SI-P-1B pump motor, will be implemented by June 30, 1999.

4. ITEM NUMBER 50-280/98-201-05

DESCRIPTION Adequacy of 4160 VAC Electrical Cables to Withstand Fault Current

COMMITMENT A Technical Report will be issued by December 1, 1998 to document the acceptability of the 4KV cable design.

5. ITEM NUMBER 50-280/98-201-06

DESCRIPTION Breaker-to-Breaker and Breaker-to-Fuse Analysis

COMMITMENT Calculation EE-0497 will be revised by November 15, 1998.

A Design Change Package (DCP) will be generated to provide additional breaker-to-breaker coordination and to support implementation by the end of the 2000 Unit 2 and 2001 Unit 1 refueling outages.

6. ITEM NUMBER 50-280/98-201-07

DESCRIPTION Breaker Replacement

COMMITMENT Work scope additions to DCP 92-099 are being prepared to replace existing breakers with the correct size breaker IAW Technical Reports, EE-0094 and EE-0095. Unit 1 breakers will be replaced by the end of the Fall 1998 refueling outage. Unit 2 breakers will be replaced by the end of the Spring 1999 refueling outage.

7. ITEM NUMBER 50-280/98-201-08

DESCRIPTION EDG Battery Transfer Switch

COMMITMENT A Design Change Package will be generated to support permanently disabling the EDG Battery transfer switch. The switch will be permanently disabled by June 30, 1999.

8. ITEM NUMBER 50-280/98-201-09

DESCRIPTION DC Tie Breaker

COMMITMENT Maintenance Operating Procedures (MOP), for removal from service and return to service of station batteries, will be revised by October 1, 1998.

9. ITEM NUMBER 50-280/98-201-10

DESCRIPTION DC Bus Tie Interlock

COMMITMENT Virginia Power will perform an evaluation to document whether modifications are warranted to comply with Safety Guide (SG) 6 by August 1, 1998.

If modifications are required, Design Change Packages will be developed to support implementation by the end of the Unit 2, 2000 refueling outage and by the end of the Unit 1, 2001 refueling outage.

10. ITEM NUMBER 50-280/98-201-11

DESCRIPTION Station Battery Calculation Discrepancies

COMMITMENT Calculation EE-0046 will be revised by March 30, 1999.

11. ITEM NUMBER 50-280/98-201-12

DESCRIPTION EDG Battery Design Margin

COMMITMENT Calculations 14937.28 and 14937.75 will be revised by December 16, 1998.

12. ITEM NUMBER 50-280/98-201-13

DESCRIPTION DC Fault Contribution

COMMITMENT An EDG Battery short circuit calculation will be completed by December 1, 1998.

13. ITEM NUMBER 50-280/98-201-14

DESCRIPTION DC Load Flow/Voltage Drop

COMMITMENT Calculation EE-0046 will be revised by March 30, 1999

The development of a new DC System transient model and calculation encompassing end components will be completed by December 1, 1999.

14. ITEM NUMBER 50-280/98-201-15

DESCRIPTION Adequate DC Component Voltage

COMMITMENT The development of a new analysis for voltage drops for EDG DC loads will be completed by December 1, 1999.

15. ITEM NUMBER 50-280/98-201-16

DESCRIPTION DC Load Control

COMMITMENT The required changes to procedures, NDCM STD-EEN-0026, "Electrical Systems Analysis" and Electrical Engineering Implementing Procedure EE-010 "Update, Review and Approval of the GDC-17 and SELL" will be completed by December 15, 1998.

Electrical Engineering Training, as noted in the response, will be completed by March 15, 1999.

16. ITEM NUMBER 50-280/98-201-17

DESCRIPTION Battery Surveillance Test

COMMITMENT Procedure revisions and capacity trending will be in place for Station batteries by September 30, 1998.

17. ITEM NUMBER 50-280/98-201-18

DESCRIPTION Fuse Control

COMMITMENT Virginia Power will review the process for ensuring that non-identical replacement fuses are processed through this IEER program and will provide enhancements to the IEER and maintenance work management process, if required, by December 15, 1998.

Virginia Power will train appropriate personnel on the IEER program as it relates to non-identical fuse replacements by March 15, 1999.

18. ITEM NUMBER 50-280/98-201-19

DESCRIPTION RS System Flow

COMMITMENT Design Changes will be implemented to eliminate non-needed flow paths for the RS system by the end of the 1998 refueling outage for Unit 1 and 1999 refueling outage for Unit 2. System flow calculations will be updated by the implementation of the DCPs to include those flowpaths that could not be eliminated.

The Containment Spray System review will be completed by December 15, 1998.

19. ITEM NUMBER 50-280/98-201-20

DESCRIPTION Unqualified Coatings

COMMITMENT The preliminary schedule for the project is January 31, 2001 for the completion of Tasks 1 and 2 as described in the response.

20. CORRECTIVE ACTION PROGRAM

COMMITMENT Revisions will be made to applicable Corrective Action Program procedures and standards by August 31, 1998 to ensure that required actions are identified, tracked and fully implemented. This evaluation will address all engineering procedures and standards for preparing calculations, technical reports, and ETs. Training will be provided to all appropriate engineering personnel by September 30, 1998 to ensure the programmatic improvements are understood and utilized.

The results of the Electrical Distribution System Functional Assessment (EDSFA) Root Cause Evaluation (RCE) will be presented to management for approval of recommended corrective actions by July 31, 1998.

21. CONFIGURATION MANAGEMENT

COMMITMENT Specific observations described in NRC Inspection Report Nos. 50-280/98-201 and 50-281/98-201 regarding design and licensing bases documents, will be reviewed to determine whether any enhancements to the existing Integrated Review Team processes are appropriate. This assessment will be completed by August 31, 1998.

22. CALCULATION DEFICIENCIES

COMMITMENT Changes will be incorporated into the calculation control program by January 31, 1999.

To upgrade the calculation availability for the electrical systems, the following calculations will be performed:

1. Cable ampacity calculations to verify cable sizing will be completed by December 1, 1998.
2. Calculations to demonstrate that the penetration circuits are within design limits will be completed by December 1, 1998.
3. Analyses to justify the sizing of the DC penetrations will be completed by December 31, 1998.
4. Analyses to examine the fault currents to the DC components and their distribution circuitry will be completed per the response to Item 50-280/98-201-13.
5. Analyses to show that the DC voltage, at the component level, is adequate to operate the devices will be completed per the responses to Items 50-280/98-201-14 & 15.