ATTACHMENT 1

PROPOSED TECHNICAL SPECIFICATIONS CHANGES

NORTH ANNA UNIT 1

VIRGINIA ELECTRIC AND POWER COMPANY

TABLE 3.2-1

DNB PARAMETERS

PARAMETER	LIMITS: 3 Loops in Operation	LIMITS: 2 Loops in Operation ** & Loop Stop Valves Open	LIMITS: 2 Loops in Operation ** & Isolated Loop Stop Valves Closed
Reactor Coolant System T_{avg}	$\leq$ 591°F		
Pressurizer Pressure	$\geq$ 2205 psig *		
Reactor Coolant System Total Flow Rate	$\geq$ 284,000 gpm ***		

* Limit not applicable during either a THERMAL POWER ramp increase in excess of 5% RATED THERMAL POWER per minute or a THERMAL POWER step increase in excess of 10% RATED THERMAL POWER.

** Values dependent on NRC approval of ECCS evaluation for these conditions.

*** The value for the minimum allowable Reactor Coolant System Total Flow Rate is reduced to 275,300 gpm until steam generator replacement.

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Power Range, Neutron Flux	Low Setpoint - ≤ 25% of RATED THERMAL POWER High Setpoint - ≤ 109% of RATED THERMAL POWER	Low Setpoint - ≤ 26% of RATED THERMAL POWER High Setpoint - ≤ 110% of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
4. Power Range, Neutron Flux, High Negative Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	≤ 30% of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 10^5 counts per second	≤ 1.3 x 10^5 counts per second
7. Overtemperature ΔT	See Note 1	See Note 3
8. Overpower ΔT	See Note 2	See Note 3
9. Pressurizer Pressure--Low	≥ 1870 psig	≥ 1860 psig
10. Pressurizer Pressure--High	≤ 2385 psig	≤ 2395 psig
11. Pressurizer Water Level--High	≤ 92% of instrument span	≤ 93% of instrument span
12. Loss of Flow	≥ 90% of design flow per loop *	≥ 89% of design flow per loop *

* Design flow per loop is one third of the minimum allowable Reactor Coolant System Total Flow Rate as specified in Table 3.2-1.

ATTACHMENT 2

DISCUSSION OF PROPOSED CHANGES

VIRGINIA ELECTRIC AND POWER COMPANY

Discussion of Proposed Changes

Introduction and Background

North Anna Power Station Unit 1 is currently involved in a mid-cycle steam generator inspection outage. An extensive eddy current inspection of the North Anna Unit 1 steam generator tubes is being performed using very conservative analysis guidelines and plugging criteria. As such, a substantially increased number of tubes are expected to be plugged.

As required by Technical Specifications 3.2.5 and 4.2.5.2, North Anna Unit 1 performs reactor coolant system (RCS) flow rate measurements once per fuel cycle. The North Anna Unit 1 safety analyses are based in part on verifying, via the Technical Specifications surveillance, that the Reactor Coolant System (RCS) total flow rate is greater than or equal to 284,000 gallons per minute (gpm). The additional steam generator tube plugging anticipated during the current mid-cycle inspection outage increases the likelihood of violating this Technical Specifications requirement. Therefore, safety analyses and evaluations have been performed which support a reduction in the RCS total flow rate limit to 275,300 gpm. The attached safety evaluation has been prepared to support the Technical Specifications change associated with the reduction in the RCS total flow rate limit.

Discussion of Proposed Changes

The predictions of steam generator tube plugging required during this mid-cycle outage are such that the RCS total flow rate measurement at restart may not meet the current Technical Specifications requirement of ≥284,000 gpm. The proposed Technical Specifications changes implement a reduced total flow rate requirement which is intended to bound future measure flow values and any required steam generator tube plugging until steam generator replacement.

Specifically, the proposed Technical Specifications change is being requested to reduce the RCS total flow rate requirement to ≥275,300 gpm, which is an approximate 3% reduction from the current Technical Specifications requirement. This reduction would only be effective until the North Anna Unit 1 steam generator replacement, which is currently scheduled to begin in January, 1993.

The proposed Technical Specifications changes affect Table 2.2-1, Reactor Trip System Instrumentation Trip Setpoints, (Technical Specification 2.2.1) and Table 3.2-1, DNB Parameters, (Technical Specification 3.2.5).

This proposed Technical Specifications change will permanently revise the footnote on the bottom of Table 2.2-1, Reactor Trip System Instrumentation Trip Setpoints, to specify that the "design flow per loop" is "one-third of the minimum allowable Reactor

Coolant System Total Flow Rate as specified in Table 3.2-1." This proposed change removes the actual numeric value for loop design flow and replaces it with a description of the derivation of the value. In effect, this change will ensure consistency between the requirements of this table and with the requirements of Table 3.2-1. This change will eliminate the need to change this requirement in the future without affecting the significance of the reactor trip setpoint value.

The trip setpoint of "≥90% of design flow per loop" continues to ensure that the safety analysis assumptions will be met.

This proposed Technical Specifications change will also temporarily revise Table 3.2-1, DNB Parameters, by adding a footnote which reduces minimum limit for Reactor Coolant System Total Flow Rate from 284,000 gpm to 275,300 gpm until the North Anna Unit 1 steam generator replacement. The proposed interim reduction in the minimum measured reactor coolant system flow is necessary to accommodate the expected increase in RCS loop resistance caused by increased steam generator tube plugging levels.

The attached safety evaluation supports the above changes to the Technical specifications. The change to Table 2.2-1 is a permanent revision, whereas, the change to Table 3.2-1 is required on an interim basis until the steam generator replacement 1993, at which time it will no longer apply.

ATTACHMENT 3

SAFETY EVALUATION

VIRGINIA ELECTRIC AND POWER COMPANY

SAFETY EVALUATION IN SUPPORT OF
REDUCED MINIMUM RCS TOTAL FLOWRATE
NORTH ANNA UNIT 1

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1.0 INTRODUCTION

The purpose of this report is to present the analyses and evaluations performed by Virginia Power to justify operation with a reduced reactor coolant system (RCS) flow rate associated with extended steam generator tube plugging (SGTP) levels. The physical consequences of extended SGTP are primarily (a) increased RCS loop resistance, resulting in a lower RCS flow rate, (b) decreased steam generator tube heat transfer area, resulting in lower steam generator outlet steam pressure, and (c) a decreased total RCS volume. The impact of these changes with respect to previously analyzed design conditions must be fully assessed for both normal operating and accident conditions. This assessment is performed following a steam generator inspection outage usually concurrent with a new reload safety evaluation (1). When required, revised safety analyses are performed and a Core Operating Limits Report (COLR) is prepared as required by Technical Specification 6.9.1.7.

In many cases, the incorporation of revised safety analyses into the North Anna design basis could be accomplished via Virginia Power processes employed to assess change per 10 CFR 50.59. However, continued operation of North Anna 1 cycle 9 with extended SGTP levels will require an accompanying change to the Technical Specifications minimum allowable Reactor Coolant System Total Flow Rate (referred to hereafter as "minimum measured flow"). The safety analyses and evaluations documented in this report have been prepared to support the Technical Specifications changes for a reduced minimum measured flow associated with extended steam generator tube plugging.

In February and March of 1991, an extensive inspection of North Anna Power Station Unit 1 steam generator tubes was performed which resulted in a substantially higher than projected level of tube plugging. Because it was assumed that future inspections would reveal similar steam generator tube degradation, an assessment of the current operating interval and the impact of tube plugging and overall tube degradation on continued operation with the existing steam generators was performed. As part of this assessment, steam generator tube plugging projections were developed for use in managing the necessary corrective measures to support continued steam generator operability, and ultimately schedule replacement of the North Anna Unit 1 steam generators. These projections estimate that a substantial percentage of the available tubes will be plugged in the current inspection outage.

An increase in the average tube plugging causes an increase in loop resistance which translates into a reduction in the RCS total flow rate passing through the core. When this flow rate becomes less than that assumed in accident analyses, it can have a significant effect on key analysis results. The latest Unit 1 flow measurement, taken April 5, 1991 at an average SGTP level of 15.1%, was 293,613 gpm versus a Technical Specifications limit of 284,000 gpm. It is expected that the current North Anna Unit 1 Technical Specifications RCS flow limit could be violated if average SGTP exceeds 20%. Following the current outage, average plugging of greater than 20% is projected. To conservatively bound the flow rates resulting from expected levels of tube plugging, Virginia Power proposes a Technical Specification minimum measured flow of 275,300 gpm, which is approximately a 3% reduction from the current

value. Because this flow rate is a critical input assumption in the UFSAR Chapter 15 analyses, it is necessary to evaluate all Chapter 15 analyses to support the implementation of extended SGTP at North Anna Unit 1.

Although the impact of reduced RCS flow and extended SGTP on many UFSAR transients was evaluated on the basis of parameter sensitivities and analysis margin, several transients were explicitly reanalyzed. These reanalyzed transients include the Loss of External Load (Section 2.5.1), the Loss of Normal Feedwater (Section 2.5.2), the Rod Bank Withdrawal at Power (Section 2.5.3), the Complete Loss of Flow (Section 2.5.4) and the Locked Reactor Coolant Pump Event (Section 2.5.5). Descriptions of these transient reanalyses, along with the evaluations of transients not reanalyzed, are presented in appropriate detail in this report.

Westinghouse and Stone and Webster have provided evaluations of the impact of reduced RCS flow and extended SGTP upon the systems and components under their design responsibility. These evaluations have confirmed the ability of each system and component to perform its respective design function under the reduced RCS flow conditions. Section 3.0 summarizes these evaluations. The conditions assumed in the safety evaluations described in this report bound the operating conditions capable of being achieved by North Anna Unit 1 under conditions of extended SGTP.

2.0 SAFETY ANALYSIS

_.1 SUMMARY OF SAFETY ANALYSIS INPUT CHANGES

As described in Section 1.0, the physical consequences of extended SGTP are primarily (a) increased reactor coolant (RCS) loop resistance, resulting in a lower RCS flow rate, (b) decreased steam generator tube heat transfer area, resulting in lower steam generator outlet steam pressure, and (c) a decreased total RCS volume. Revised safety analyses or evaluations were performed to assess the impact of the proposed increased SGTP on previously analyzed design conditions during both normal operating and accident conditions.

A revised RCS minimum measured flow rate of 275,300 gpm, which is approximately 3% lower than the current T.S. 3.2.5 RCS flow rate, was selected for the extended SGTP analyses based on a conservative assessment of current trends in measured RCS flow rate vs. steam generator tube plugging fractions. This value is appropriate for use in statistical Departure from Nucleate Boiling (DNB) accident analyses. Similarly, for deterministic DNB and non-DNB analyses a thermal design flow rate of 269,800 gpm was selected. This value includes allowance for flow measurement uncertainty (2%).

The accident reanalyses discussed in Section 2.5 assume an average RCS temperature of 586.8°F and 2893 MW core thermal power. These are the current limiting Technical Specifications values. Available analyses and

assessments demonstrate that the conclusions drawn herein are valid for full power RCS average temperatures as low as 580.8°F. The bounding core physics parameters assumed in the most recent Unit 1 Reload Safety Evaluation were assumed in all transient reanalyses. Table 2.1-1 provides additional information on key analysis assumptions.

Steam generator steam pressure is reduced as a function of steam generator tube plugging level. Westinghouse has d[illegible]ped revised design steam pressures of 766 psia at 30% SGTP, 740 psia at 35% SGTP, and 711 psia at 40% SGTP. These revised steam pressures have been incorporated into analysis models at the SGTP level appropriate for the specific transient analysis.

Revised one- and two-loop RETRAN (2),(3) models were developed which explicitly account for the effects of extended SGTP on RCS flow, RCS loop flow resistance, steam generator heat transfer area, steam generator tube metal volume, and secondary side steam pressure. These models were utilized in the reanalyses discussed in Section 2.5.

TABLE 2.1-1

KEY ANALYSIS ASSUMPTIONS DETAILS

Initial Conditions

	Statistical DNB Method	Deterministic Method
Power	2893.0 MWt	2950.86
Average Temperature	586.8 °F	590.8 °F
RCS Flow Rate	275,300 gpm	269,800 gpm
Pressure	2250 psia	2187/2280
FΔh at Rated Power	1.49	1.55

1.55-Cosine Axial Power Profile

2.2 EVALUATION OF RETAINED DNBR MARGIN

The Statistical DNBR Evaluation Methodology (4) implementation analysis for North Anna Unit 1 (5),(6) established a statistical DNBR limit (SDL) of 1.26. The difference between this value and the WRB-1 CHF correlation (7),(8) limit of 1.17 represents the impact of combining key DNBR analysis parameter uncertainties in a statistical manner. Transient analysis results are assessed against a 1.46 design DNBR limit. The percentage difference between the design DNBR limit and the SDL represents generic retained margin, against which penalties may be assessed to account for the DNB effect of changes in plant operating conditions or analysis methodology. Analysis DNBR margin is the percentage difference between the minimum transient analysis DNBR and the design DNBR limit. Although it is atypical, this margin has been occasionally utilized to justify changes in plant operating conditions.

The assessment of penalties against generic retained margin is typically accomplished through the use of a DNBR partial derivative. To facilitate the evaluation of the proposed reduction in RCS flow rate, the maximum DNBR partial derivative with respect to RCS flow rate was calculated by examining the marginal effect of changes in RCS flow on DNBR over a range of operating conditions. The product of the percentage reduction in RCS flow rate, and the bounding DNBR partial derivative with respect to flow, provides a penalty which may be assessed against available retained margin to account for the effect of the RCS flow reduction.

A DNBR penalty of 4.8% was calculated based on a reduction of 3.0% in RCS minimum measured flow rate, and a bounding DNBR partial derivative of 1.6% (% change in DNBR / % change in flow). It has been determined that there is adequate available generic retained DNBR margin to accommodate this penalty without taking credit for analysis margin. As discussed in Section 2.3, this penalty will be extracted from available Core Thermal Limit retained DNBR margin to ensure that bounding Core Thermal Limit protection is provided by the existing OTΔT and OPΔT reactor protection system functions for flow rates as low as the proposed reduced minimum measured flow rate. The DNBR penalty will also be applied to those transients which were not reanalyzed, but were evaluated and determined to require a DNBR penalty to account for the effect of the flow reduction on minimum predicted transient DNBR. Those transients which were reanalyzed require no penalty to be assessed, as the reanalyses explicitly accounted for the effects of a reduced RCS flow rate (and other effects related to steam generator tube plugging).

It is recognized that the assessment of a DNBR penalty against retained margin in the manner described above neglects any effect of the flow reduction on transient dynamics. The reduction in RCS flow rate is, in general, sufficiently small that the impact of the flow reduction on transient dynamics is offset by the use of a bounding DNBR partial derivative. All cases for which this assumption might be questionable have been explicitly reanalyzed. (See Section 2.5.)

2.3 IMPACT OF FLOW REDUCTION ON CORE THERMAL LIMITS AND REACTOR PROTECTION SYSTEM SETPOINTS

An evaluation has been performed to assess the impact of the proposed reduction in minimum measured flow rate on North Anna Unit 1 core thermal limits, overtemperature and overpower ΔT trip setpoints, and the $F(\Delta I)$ function.

The current Core Thermal Limits in Figure 2.1-1 of the Technical Specifications consist of two distinct limits. The DNBR portions of the limit lines are based on a minimum measured flow of 289,200 gpm and bound a design DNBR limit of 1.46 (vice a statistical DNBR limit of 1.26). The vessel exit portions of the limit lines are based on a thermal design flow of 278,400 gpm.

The proposed reduced minimum measured flow rate of 275,300 gpm is used for statistical DNBR analysis. A penalty against retained DNBR margin was defined in Section 2.2 to compensate for the impact of the reduction in minimum measured flow rate. Similar to the previous flow reduction to a minimum measured flow of 284,000 gpm (9), there is sufficient retained margin in the Core Thermal Limits to absorb this penalty. Therefore, the DNB portions of the existing core thermal limits continue to remain bounding.

The vessel exit boiling limited portions of the core thermal limits were evaluated with the proposed reduced non-statistical (deterministic) thermal design flow rate of 269,800 gpm (which corresponds to a minimum

measured flow rate limit of 275,300 gpm). A review of the current vessel exit boiling limits shows that they contain more than enough conservatism to offset the small impact (<1°F) of the reduced design flow. Therefore, the Core Thermal Limits established in the Technical Specifications remain bounding for operation at the reduced RCS flow rate.

The existing Technical Specifications OTΔT and OPΔT setpoints and the F(ΔI) function were demonstrated to provide bounding protection for the proposed reduced minimum measured flow rate. This included specific accident reanalysis as indicated in this report. For those DNB-limited transients which were not reanalyzed, bounding protection is attained by the assessment of a DNBR penalty against available retained DNBR margin to compensate for the impact of the reduction in minimum measured flow rate. The development of this penalty was discussed in Section 2.2.

2.4 SUMMARY OF ACCIDENT EVALUATIONS

This section discusses the UFSAR Chapter 15 accidents for which evaluations were performed to support a reduction in the Technical Specifications Reactor Coolant System Total Flow Rate ("minimum measured flow rate") associated with extended SGTP at North Anna Unit 1. For each accident, a brief description of the transient, its analysis, and how the analysis is impacted by the reduced RCS flow rate is provided. A discussion is provided which demonstrates that the impact of the proposed flow reduction on the accident analysis results is accommodated by current analysis margins. Section 2.5 provides descriptions of the reanalyses performed for those transients which were determined by evaluation to be potentially impacted by the proposed reduction in the Technical Specification minimum measured RCS flow rate associated with extended SGTP.

2.4.1 Accidental Depressurization of the RCS (UFSAR Section 15.2.12).

The most severe core conditions resulting from an accidental depressurization of the reactor coolant system are associated with the inadvertent opening of a pressurizer safety valve. Initially, the event results in a rapidly decreasing reactor coolant system pressure until this pressure reaches a value corresponding to the hot-leg saturation pressure. At that time, the pressure decrease is slowed considerably. The pressure continues to decrease, however, throughout the transient. The effect of the pressure decrease would be to decrease the neutron flux

via the moderator density feedback, but the reactor control system (if in the automatic mode) functions to maintain the power essentially constant throughout the initial stage of the transient. The average coolant temperature decreases slowly, but the pressurizer level increases until reactor trip.

The analysis of the Accidental Depressurization of the RCS transient is performed to ensure that the minimum DNBR remains above the DNBR design limit throughout the transient. The impact of reduced RCS flow due to extended SGTP on the DNBR results of the Accidental Depressurization of the RCS analysis has been fully accommodated by a single penalty assessed against available retained DNBR margin. The development of this penalty is described in Section 2.2.

2.4.2 Accidental Depressurization of the Main Steam System (UFSAR Section 15.2.13).

The most severe core conditions resulting from an accidental depressurization of the main steam system are associated with an inadvertent opening of a single steam dump, relief, or safety valve. The analyses performed in consideration of a main steam pipe rupture are presented in UFSAR Section 15.4.2.1 (Main Steamline Break Accident).

The steam release which occurs during this accident removes energy from the RCS, causing a reduction in RCS temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin.

The current evaluation is performed to demonstrate that, in the presence of a stuck rod cluster control assembly and a single failure in the engineered safety features, there will be no departure from nucleate boiling in the core for a steam release equivalent to the opening (with failure to close) of the largest of any single steam dump, relief, or safety valve.

Extended SGTP reduces the steam generator's capacity to remove energy from the RCS. Because the primary effect of an accidental depressurization of the main steam system is to decrease RCS temperature and pressure, and to increase core power (given an end-of-cycle negative moderator temperature coefficient), a reduced capacity to remove energy from the RCS due to extended SGTP would act to further limit the severity of the reactor coolant temperature decrease. The impact of a 3% reduction in RCS flow rate is accommodated by a penalty assessed against transient-specific retained DNBR margin. In addition, analysis margin (margin between the minimum analysis DNBR and the design DNBR limit) is substantial for this event. Therefore the existing UFSAR analysis conclusions will remain valid for the reduced RCS flow condition.

2.4.3 CVCS Malfunction (Boron Dilution) (UFSAR Section 15.2.4).

A reduction in the minimum measured flow rate has no direct consequences on the analysis of the boron dilution event. The presently specified NA-1&2 TS 3.1.1.3.2 precludes the possibility of an unplanned boron dilution by specifying that the primary grade water flow control valve be locked closed during operations in Modes 3, 4, 5, and 6 except

during planned boron dilution or makeup activities. The current SRP (Standard Review Plan) acceptance criteria are met through this presently specified NA-1&2 TS 3.1.1.3.2.

As a reactivity insertion transient, the consequences of a boron dilution event at power (in terms of approach to the design DNBR limit) are bounded by those of the rod bank withdrawal event, which was reanalyzed as described in Section 2.5.3. The impact on the boron dilution at power analysis of the reduction in RCS volume associated with extended SGTP will be considered as part of the analysis supporting North Anna 1 Cycle 9 restart. Therefore, no reanalysis of this event is required to support the proposed Technical Specifications changes.

2.4.4 Excessive Load Increase (UFSAR Section 15.2.11).

An excessive load increase is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10% step load increase or a 5%/minute ramp load increase in the range of 15 to 100% of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system.

The end of life cases (with and without automatic rod control) were demonstrated to be limiting, since the RCS cooldown due to load increase has the maximum impact on core power at end of life.

In both the automatic and manual reactor control end-of-life cases, the DNBR remains well above the DNBR limit. The impact of reduced RCS flow due to extended SGTP on the DNBR results of the Excessive Load Increase analysis has been fully accommodated by a single penalty assessed against available retained DNBR margin. The development of this penalty is described in Section 2.2.

2.4.5 Excessive Heat Removal (Feedwater Malfunction) (UFSAR Section 15.2.10).

Reductions in feedwater temperature or additions of excessive feedwater are means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the secondary plant and of the reactor coolant system. The reactor protection system (high flux, overtemperature delta-T (OTΔT), and overpower delta-T (OTΔT) trips) prevents any power increase that could lead to a DNBR less than the limit value.

For the currently applicable analyses of both the automatic and manual reactor control end-of-life cases, the DNBR remains well above the DNBR limit. The impact of reduced RCS flow due to extended SGTP on the DNBR results of the Excessive Load Increase analysis has been accommodated by a single penalty assessed against available retained DNBR margin. The development of this penalty is described in Section 2.2.

2.4.6 Control Rod Drop/Misalignment (UFSAR Section 15.2.3).

When operating at power, a single or multiple dropped control rod may result in a transient leading to reduced margins to fuel design limits and, in particular, to DNB limits. This would be a result of increased power distribution peaking factors with the inserted (dropped) rods and a possible "return to power" transient produced by feedback or automatic control. Depending on the control system, the "return to power" transient could result in a power level in excess of the initial level.

Normally the plant is protected from exceeding DNB limits through a negative flux rate trip system. The system will sense the initial rapidly decreasing neutron flux (as a negative rate) and trip the reactor to end the event. For some events, however, the flux decrease rate may be insufficient to generate a trip.

Reference (10) describes a dropped rod analysis methodology developed by Westinghouse and funded by the Westinghouse Owner's Group (WOG). This methodology is an extension of the methodology of Reference (11) and eliminates the need to take credit for the negative flux rate trip.

Virginia Power implemented the Westinghouse methodology for performing the dropped rod analyses using the methods of Reference (10), although the negative flux rate trip has been retained at North Anna. Virginia Power has performed evaluations which show the applicability of the methodology, the correlations, and the transient database for analysis

of the dropped rod event for North Anna Units 1 and 2 using Virginia Power core design and transient analysis computer codes.

Dropped rod DNBR limit lines applicable to reduced RCS flow conditions have been developed for application of the Reference (10) methodology to reload cores designed under conditions of reduced flow. Because these limit lines are specifically applicable to conditions of reduced flow, no cycle-specific penalty against available DNBR retained margin need be assessed. Cycle 9 operation with reduced RCS flow will be assessed against these revised dropped rod limit lines prior to restart.

2.4.7 Partial Loss of Flow (UFSAR Section 15.2.5).

A partial loss of coolant flow accident can result from a mechanical or electrical failure in a reactor coolant pump, from a fault in the power supply to the pump, or from inadvertent closure of a loop isolation valve. If the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not tripped promptly.

The results of the partial loss of flow accident analysis are bounded by those of the complete loss of flow event, which is reanalyzed in Section 2.5.4. Because the event has not been explicitly reanalyzed to evaluate the impact of the reduced RCS flow rate associated with extended SGTP, a penalty from available retained DNBR margin has been assessed. The development of this penalty is described in Section 2.2.

2.4.8 Rod Withdrawal from Subcritical (UFSAR Section 15.2.1).

A rod cluster control assembly withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of the rod cluster control assemblies, thereby producing a power excursion. Potential causes of the event include malfunctions of the reactor control and control rod drive systems, and operator error. At cold shutdown, protection against the consequences of this accident are provided by the high source range count rate trip. At hot standby and hot shutdown, protection is provided by the source range trip. During startup and at power, protection is provided by the intermediate range or power range high neutron flux reactor trips, or by the intermediate and power range rod stops.

The neutron flux response to a continuous reactivity insertion is characterized by an exponential increase. Once the amount of reactivity inserted equals the delayed neutron fraction for the core, the power increase is very rapid, and is terminated by the reactivity feedback effect of the negative doppler coefficient. This self-limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. This event is non limiting from a DNBR standpoint since the peak heat flux attained during the transient is substantially below that at hot full power.

The impact of a reduction in RCS flow rate due to extended SGTP on the DNBR results of the rod withdrawal from subcritical analysis has been

fully accommodated by a single penalty assessed against available retained DNBR margin. The development of this penalty is described in Section 2.2.

2.4.9 Inactive Loop Startup (UFSAR Section 15.2.6).

An analysis of the inactive Loop Startup event from reduced power is provided in the UFSAR; however, the initial system configuration and conditions assumed in the analysis of the inactive loop startup event are precluded from occurrence by Technical Specifications. The probability of occurrence or consequences of the event (both minimum DNBR and reactivity insertion due to boron dilution aspects) are, therefore, not affected by the reduction in RCS flow rate associated with extended SGTP.

2.4.10 Spurious Operation of the Safety Injection System (UFSAR Section 15.2.14).

Spurious safety injection system operation at power could be caused by operator error or a false electrical actuating signal. Following the actuation signal, the suction of the coolant charging pumps is diverted from the volume control tank to the refueling water storage tank. The valves isolating the boron injection tank from the charging pumps and the valves isolating the boron injection tank from the injection header then automatically open. The charging pumps then force boric acid solution from the boron injection tank through the header and injection line, and into the cold legs of each loop. The low head safety injection pumps also start automatically but provide no flow when the reactor coolant system

is at normal pressure. The passive injection system also provides no flow at normal RCS pressure.

The analysis presented in the UFSAR reveals that the transient does not challenge the integrity of the RCS, and that the transient DNBR remains above the initial value.

Although this is a non-limiting DNB event, the impact of a reduction in RCS flow rate due to extended SGTP on the DNBR results of the spurious safety injection analysis will be accommodated by a single penalty assessed against available retained DNBR margin. The development of this penalty is described in Section 2.2.

2.4.11 Small Break LOCA (UFSAR Section 15.3.1)

Analysis results for this transient have been demonstrated to be insensitive to marginal changes in RCS flow rate. The effects of RCP operation for this transient have been conservatively incorporated into the Westinghouse evaluation model as described below.

Virginia Power employs the Westinghouse NOTRUMP Evaluation Model (12), (13) for analysis of this event. The features of this model relating to reactor coolant pumps and flow comply with the requirements in 10 CFR 50, Appendix K, including the pump trip requirements of NRC Generic Letters 83-10c and 83-10d (14). As described in Reference (13), the key evaluation model feature relating to pump modeling for small break LOCA is whether the pumps continue to run or are tripped early in the event.

The [illegible] flow rate is not a critical consideration in [illegible] treatment [illegible] CPs. The conclusions pre[illegible] (13) indicate that the behavior of small break LOCAs with and [illegible] RCP operation which were established with the WFLASH model ( ) are applicable for analyses with NOTRUMP. For the design Appendix K analysis, it has been concluded that the conservative assumption is to assume that RCPs trip at the time of reactor trip due to loss of offsite power. The [illegible]ASH RCP trip study (15) concluded that if the RCPs are tripped in accordance with Westinghouse Emergency Operating Procedure Guidelines, the system thermal/hydraulic behavior and calculated PCT will be almost identical to that obtained with the design analysis.

For the present North Anna Unit 1 evaluation, it is therefore concluded that the existing analysis provides an assessment which remains valid for operation with the proposed reduction in RCS flow. The effects of extended SGTP upon the small break LOCA results will be assessed as part of the safety evaluation for the resumption of North Anna Unit 1, Cycle 9 operation.

2.4.12 Minor Secondary Steam Pipe Breaks (UFSAR Section 15.3.2) (UFSAR Section 15.2.14).

Section 15.3.2.1 of the North Anna UFSAR presents the description and results of the most recent evaluation of minor secondary system pipe breaks. The section concludes that the analyses presented in Section 15.4.2.1 of the UFSAR (Main Steamline Break) demonstrate that the

consequences of a minor secondary system pipe break are acceptable, since a DNBR less than the DNBR limit does not occur even for a larger secondary system pipe break. The evaluation of the main steamline break event for the proposed reduction in the minimum measured RCS flow rate is presented in Section 2.4.19.

2.4.13 Misloaded Fuel Assembly (UFSAR Section 15.3.3)

Fuel and core loading errors, such as those that can arise from the inadvertent loading of one or more fuel assemblies into improper positions, loading a fuel rod during manufacture with one or more pellets of the wrong enrichment, or the loading of a full fuel assembly during manufacture with pellets of the wrong enrichment will lead to increased heat fluxes if the error results in placing fuel in core positions calling for fuel of lesser enrichment. Also included among possible core-loading errors is the inadvertent loading of one or more fuel assemblies requiring burnable poison rods into a new core without burnable poison rods.

The UFSAR Section 15.3.3 analysis of the misloaded fuel assembly accident indicates that the consequences of this accident are limited either by administrative controls or operational actions in response to the detection of a misloaded assembly. As such, no further evaluation is necessary to support operation with the reduced minimum measured RCS flow rate.

2.4.14 Single Rod Withdrawal at Power (UFSAR Section 15.3.7)

The Single Rod Withdrawal at Power event produces a system transient response which is similar to the uncontrolled control bank assembly withdrawal; that is, it results in an increase in core heat flux and a mismatch between core power generation and power removal by the steam generators. This power mismatch, which persists until the steam generator pressure reaches the relief or safety valve setpoint, causes an increase in the primary coolant temperature. The transient would result in a violation of the core thermal limits if not terminated by either manual or automatic action.

The impact of reduced RCS flow due to extended SGTP on the DNBR results of the Single Rod Withdrawal at Power analysis has been fully accommodated by a single penalty assessed against available retained DNBR margin. The development of this penalty is described in Section 2.2.

2.4.15 Volume Control Tank Rupture (UFSAR Section 15.3.6)

The analysis of the volume control tank rupture is in no way affected by the proposed reduction in the minimum measured RCS flow rate, since RCS volume and flow rate are not analysis input parameters for this event.

2.4.16 Waste Gas Decay Tank Rupture (UFSAR Section 15.3.5)

The analysis of the waste gas decay tank rupture is in no way affected by the proposed reduction in the minimum measured RCS flow rate, since RCS volume and flow rate are not analysis input parameters for this event.

2.4.17 Fuel Handling Accident Outside Containment (UFSAR Section 15.4.5)

The analysis of fuel handling accidents outside containment is in no way affected by the proposed reduction in the minimum measured RCS flow rate, since RCS volume and flow rate are not analysis input parameters for this event.

2.4.18 Fuel Handling Accident Inside Containment (UFSAR Section 15.4.7)

The analysis of fuel handling accidents inside containment is in no way affected by the proposed reduction in the minimum measured RCS flow rate, since RCS volume and flow rate are not analysis input parameters for this event.

2.4.19 Major Secondary System Pipe Ruptures (Main Steamline Break) (UFSAR Section 15.4.2.1).

The steam release resulting from the rupture of a main steam pipe removes energy from the reactor coolant system, and causes a reduction in RCS temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin. If the most reactive rod cluster control assembly (RCCA) is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential problem mainly because of the high power peaking factors associated with the stuck RCCA. The core is ultimately shut down by the boric acid injection delivered by the safety injection system.

The main steamline break analysis is performed to demonstrate that there would be no core damage due to the onset of DNB, and that the energy release to containment does not cause failure of the containment structure.

Extended SGTP reduces the steam generator's capacity to remove energy from the RCS. Because the primary effect on the RCS of a main steamline

break is to decrease RCS temperature and pressure, and to increase core power (given an end-of-cycle negative moderator temperature coefficient), a reduced capacity to remove energy from the RCS due to extended SGTP will tend to make the cooldown due to MSLB less severe (i.e., behave like a smaller break size). The calculated transient DNBR under conditions of extended steam generator tube plugging would be less limiting than the current licensing analysis. Because the RCS cooldown associated with smaller steamline breaks is lower, the transient RCS pressure in smaller breaks is higher, and the transient safety injection flow is lower. However, despite the lower safety injection flows, the DNBR's of smaller steamline breaks are predicted to be less limiting than those of larger breaks.

MSLB statepoints are evaluated for each reload core design. The impact of reduced RCS flow due to extended SGTP on the DNBR results of the main steamline break analysis has been fully accommodated by a single penalty assessed against available retained DNBR margin. As described in Section 2.1, the proposed minimum RCS flow rate for analyses with a deterministic treatment of uncertainties is 269,800 gpm, which represents a reduction of approximately 3% from the analysis assumed flow rate of 278,400 gpm. Utilizing bounding sensitivities at conditions associated with MSLB, the flow reduction translates into a 4.3% penalty to be assessed against available main steamline break analysis retained margin. This penalty quantifies the incremental impact on the transient analysis minimum DNBR without consideration for the dynamic effects of the reduced RCS flow on transient behavior, which would be insignificant.

2.4.20 Rupture of a Main Feedwater Pipe (Main Feedline Break) (UFSAR Section 15.4.2.2).

A major feedwater line rupture is defined as a break in a feedwater pipe large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell-side fluid inventory in the steam generators. If the break is postulated in a feedline between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of auxiliary feedwater to the affected steam generator. A break upstream of the feedline check valve would affect the nuclear steam supply system only as a loss of feedwater. (See Section 2.5.2).

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system cooldown (by excessive energy discharge through the break) or a reactor coolant system heatup. Potential reactor coolant system cooldown resulting from a secondary pipe rupture is evaluated in UFSAR Section 15.4.2.1. (See Section 2.4.19.) Therefore, only the reactor coolant system heatup effects are evaluated for a feedline rupture.

The consequences of feedline break events upstream of the feedline check valve are bounded in severity by the consequences of the loss of normal feedwater event which has been reanalyzed for the reduction in RCS flow rate associated with extended SGTP as described in Section 2.5.2.

As described in the following, the consequences of feedline break events for breaks downstream of the check valve have been evaluated to assess the impact of extended steam generator tube plugging.

The key analysis acceptance criterion is the minimum RCS subcooling margin experienced during the transient. For the existing analysis, the subcooling margin is 36°F. A study of the sensitivity of analysis results to changes in RCS flow rate and steam generator tube plugging levels was performed which indicated a total reduction in subcooling margin of less than 10°F. On the basis of these results, it may be concluded that the proposed reduction in minimum measured RCS flow rate associated with extended SGTP is easily accommodated by available analysis margin.

2.4.21 Control Rod Ejection (UFSAR Section 15.4.6).

The control rod ejection transient is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of a rod cluster control assembly and drive shaft. The consequence of this mechanical failure is a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

The analysis methodology for the control rod ejection accident is documented in Reference (16); the most recent analysis is documented in the UFSAR.

The Reference (16) Rod Ejection Topical Report presents sensitivity data that is suitable for evaluating the impact of the RCS flow reduction due to extended SGTP on the results of the current design basis rod ejection analysis. Of particular interest is the sensitivity to a 5% reduction in RCS mass flow rate which shows a 2.0°F increase in maximum centerline temperature, a 36°F increase in maximum cladding temperature, and a 1.0 BTU/lbm increase in maximum fuel pellet enthalpy. Of these changes, only the maximum cladding temperature increase can be considered significant. When this bounding sensitivity is applied to the most limiting maximum clad temperature result (zero power case at end of life), a temperature increase from 2575°F to 2611°F would be predicted. This result is well below the 2700°F temperature at which clad embrittlement is predicted to occur. It may be concluded that the proposed increased SGTP does not cause the results of the rod ejection transient to exceed their respective analysis criteria limits.

2.4.22 Steam Generator Tube Rupture (UFSAR Section 15.4.3).

The steam generator tube rupture accident is defined as the complete severance of a single steam generator tube. The accident is assumed to take place at power, with the reactor coolant contaminated with fission products consistent with the coolant activity limits set forth in the Technical Specifications. The accident leads to an increase in contamination of the secondary system due to leakage of radioactive coolant from the reactor coolant system. In the event of a coincident loss of offsite power, or failure of the condenser dump system, discharge

of activity to the atmosphere takes place via the steam generator safety and or power operated relief valves.

In analyzing the dose consequences of a SGTR, operator action is assumed to terminate the primary to secondary mass transfer due to the tube rupture within 30 minutes. In addition, bounding values of key parameters affecting the calculated consequences are assumed. The proposed reduction in RCS flow rate associated with extended SGTP will not adversely affect the operator's ability to respond to and effectively control a SGTR event; the calculated consequences of a SGTR will be unchanged.

2.4.23 Large Break LOCA (UFSAR Section 15.4.1).

A reanalysis of the large break LOCA was not performed to support the proposed reduction in the minimum measured RCS flow rate associated with extended SGTP at North Anna Unit 1. As described below, analysis results for this transient have been demonstrated to be to be insensitive to marginal changes in RCS flow.

Virginia Power employs the Westinghouse 1981 Evaluation Model with BASH (17) for analysis of this event. The features of this model relating to reactor coolant pumps and flow comply with the requirements in 10 CFR 50, Appendix K. Section I.C.6, "Pump Modeling" states the general requirement for a pump model and the justification of its flow characteristics. In addition, Section I.D.3, "Calculation of Reflood Rate for Pressurized Water Reactors," requires that primary system

coolant pumps shall be assumed to have locked impellers if this assumption leads to the maximum calculated cladding temperature. The Westinghouse evaluation model incorporates this assumption.

These required evaluation model features tend to minimize the impact of variations in steady-state coolant pump flow upon results for large break LOCA analysis. The PCT impact is essentially limited to the effect upon steady-state coolant temperatures associated with the coolant pump flow. Reduced RCS flow will also cause reduced core inlet temperature, which for the purpose of LOCA analysis, is analogous to an RCS Tavg reduction. Virginia Power sensitivity data indicates that the inlet temperature reduction associated with the proposed RCS flow decrease would cause peak cladding temperature (PCT) to increase by approximately 2°F. This is considered insignificant in relation to the conservative effects obtained by use of the required pump features of Appendix K. For the current North Anna Unit 1 assessment it is concluded that the existing analysis provides an assessment which remains conservative for operation with the proposed reduction in RCS flow.

The effects of extended SGTP upon the large break LOCA results will be assessed as part of the safety evaluation for the resumption of North Anna Unit 1, Cycle 9 operation.

2.5 SUMMARY OF REANALYZED ACCIDENTS

This section provides descriptions of the reanalyses performed for those transients which were determined to be potentially impacted by the proposed reduction in minimum measured flowrate associated with extended SGTP.

The system transient portion of these analyses was performed using the Virginia Power RETRAN system transient analysis code single and double loop models (2), (3). The models were modified to appropriately reflect the effects of reduced RCS flowrate associated with extended SGTP. Specifically, RCS flow rates, steam generator tube heat transfer areas (outside and inside the tubes), SG tube metal volume (heat capacity), and SG tube side flow area were reduced to reflect plugging effects. Steam generator secondary pressures were adjusted to be consistent with the data discussed in Section 2.1.

A summary of important analysis initial conditions and parameters is provided in Table 2.1-1.

2.5.1 Loss of External Load Reanalysis (UFSAR Section 15.2.7).

The Loss of External Load accident has been reanalyzed to assess the impact of reduced minimum measured flowrate associated with extended SGTP. A discussion of the reanalysis is presented in the following sections.

2.5.1.1 Accident Description

A loss of load event can result from loss of external electrical load or from a turbine trip. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps.

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power without a direct reactor trip, primarily to show the adequacy of the pressure-relieving devices and also to demonstrate core protection margins.

Among the UFSAR cases, the BOC with Pressure Control Case and the BOC without Pressure Control Cases are the limiting cases for DNB and overpressurization concerns, respectively. These cases have been reanalyzed to determine the impact of the reduced minimum measured flowrate and SGTP on the Loss of Load accident.

2.5.1.2 Method of Analysis

The complete load loss event was reanalyzed with the RETRAN (2),(3) system transient analysis code. All assumptions were consistent with or conservative with respect to those in the previously approved analysis (5),(6). A summary of key analysis assumptions is presented in the following.

1. Initial Operating Conditions - For the DNB-limited portion of this transient analysis, the initial reactor power, temperature, and pressure are assumed to be at their steady state, full power, nominal values. Allowances for calibration and instrument errors are incorporated into the DNBR limit value as described in References (4), (6), and (5).

   The overpressure portion of this transient is performed by deterministic application of these uncertainty values: 2% on reactor power, 4°F in average RCS temperature, 30 psi in pressurizer pressure, and deterministic thermal design flow were assumed. These assumptions result in the maximum power difference for the load loss, and the minimum margin to core protection limits at the initiation of the accident.

2. Moderator and Doppler Coefficients of Reactivity - A bounding positive moderator temperature coefficient is assumed for beginning of life conditions. The analysis used appropriate values of BOL Doppler power coefficient.

3. Reactor Control - From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual control.

4. Steam Release - No credit is taken for the operation of the condenser steam dump system or steam-generator power-operated relief valves. The steam-generator pressure rises to the safety valve setpoint, where steam release through safety valves limits secondary steam pressure.

5. Pressurizer Spray and Power-Operated Relief Valves - Two cases for both the beginning and end of life were analyzed:

   a. Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the RCS pressure.

   b. No credit is taken for the effect of pressurizer spray and power-operated relief values in reducing or limiting the RCS pressure.

6. Pressurizer Safety Valves - Valves are assumed to relieve at 3% above the Technical Specification lift setpoint in conjunction with 3% pressure accumulation.

7. Feedwater Flow - For both the overpressure and DNB analyses, main feedwater flow to the steam generators is conservatively assumed to be lost early in the transient. In actuality, the feedwater flow would continue until the RCS temperature dropped to well below the initial value. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

Reactor trip is actuated by the first reactor protection system trip setpoint reached, with no credit taken for the direct reactor trip on the turbine trip.

2.5.1.3 Results and Conclusions

For the limiting DNB case (BOC with pressure control), the calculated DNBR increased throughout the transient from the initial value of 2.15. Peak RCS pressure in the limiting pressure case (BOC without pressure control) is 2676 psia, which meets the acceptance criterion of 2750 psia. Peak main steam pressure is 1166 psia, which is within the acceptance limit of 1210 psia.

The results of the analysis support the conclusion that a total loss of external electrical load (a) without a direct or immediate reactor trip, (b) with 3% tolerance and 3% accumulation PSV setpoint modelling and (c) with extended steam generator tube plugging presents no hazard to the integrity of the reactor coolant system or the main steam system. Pressurizer and main steam safety valves are adequate to maintain the maximum pressures within the design limits. Furthermore, the integrity

of the core is maintained by operation of the reactor protection system, i.e., the DNBR will be maintained above the limit value. Thus there will be no cladding damage and no release of fission products to the reactor coolant system.

2.5.2 Loss of Normal Feedwater (Loss of Offsite AC) Reanalysis (UFSAR Section 15.2.8/15.2.9).

The Loss of Normal Feedwater accident, has been reanalyzed to assess the impact of reduced thermal design flow associated with extended SGTP. A description of the reanalysis is presented in the following sections.

2.5.2.1 Accident Description

A loss of normal feedwater (due to pump failures, valve malfunctions, or loss of offsite AC power) results in a reduction in the capability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during the accident, core damage could occur from a loss of heat sink. If an alternative supply of feedwater were not supplied to the plant, residual heat following reactor trip would heat the primary system water to the point where water relief from the pressurizer occurs. Significant loss of water from the reactor coolant system could conceivably lead to core damage. Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a DNB condition.

The following provide the necessary protection against a loss of normal feedwater:

1. Reactor trip on low-low water level in any steam generator, or on water level below the AMSAC setpoint in two steam generators after a time delay, providing permissive C-20 is satisfied.

2. Reactor trip on low feedwater flow signal in any steam generator. (This signal is actually a steam/feedwater flow mismatch in coincidence with low water level.)

3. Two motor-driven auxiliary feedwater pumps (capable of delivering at least 340 gpm each) that are started on

   a. Low-low level in any steam generator,

   b. Trip of all main feedwater pumps,

   c. Any safety injection signal,

   d. Loss of offsite power,

   e. Manual actuation,

   f. AMSAC actuation.

4. One turbine-driven auxiliary feedwater pump (capable of delivering at least 700 gpm) which is started on the same signals as the motor-driven pumps.

The motor-driven auxiliary feedwater pumps are supplied by the diesel generators if a loss of offsite power occurs; the turbine-driven pump uses steam from the secondary system. Both pump types are designed to start within one minute even if a loss of AC power occurs simultaneously with a loss of normal feedwater. The auxiliary pumps take suction from a condenser water storage tank for delivery to the steam generators.

The loss of normal feedwater accident analysis must demonstrate that the auxiliary feedwater system is capable of removing the stored and residual heat following a loss of normal feedwater, and preventing either overpressurization of the reactor coolant system or loss of water from the reactor coolant system. The results of the accident analysis establish the minimum flow requirement for the auxiliary feedwater pumps.

2.5.2.2 Method of Analysis

The complete loss of normal feedwater event was reanalyzed with the RETRAN system transient analysis code (2), (3). All assumptions were consistent with or conservative with respect to those in the previously approved analysis (18),(19) with the exception of the heat transfer coefficient modelling during the time between loss of feedwater and initiation of auxiliary feedwater. Although the secondary side heat transfer coefficients used were higher than those associated with the previously assumed stagnated flow, pool boiling heat transfer, the heat transfer coefficients used in this analysis remain conservatively low with respect to the expected values for actual plant operating conditions.

The analysis assumed the loss of normal feedwater to all steam generators as the initiating event. Reactor trip was assumed to occur on low-low steam generator level. Auxiliary feedwater flow from two motor driven pumps was initiated 60 seconds after the steam generator reaches the low-low level.

For conservatism, pressurizer and steam generator power operated relief valves and pressurizer pressure control were assumed to be unavailable. The pressurizer high pressure, pressurizer high level, and overtemperature/overpower ΔT trips were assumed not to function. Reactor coolant system pressure, temperature, power and flow measurement uncertainties, and uncertainties in initial pressurizer and steam generator levels were considered. Reactivity parameters were established at values demonstrated to most adversely impact the transient analysis

results. Decay heat was assumed to be 1.2 times the 1971 ANS standard value. Cases were analyzed both with offsite power assumed to be available and with offsite power unavailable.

2.5.2.3 Results

Following termination of normal feedwater flow and reduction of heat transfer to the secondary side, reactor coolant system temperatures, pressurizer pressure and pressurizer liquid volume began to increase. At approximately 30 seconds after loss of feedwater, the reactor and turbine tripped on low steam generator level; RCS temperatures and pressurizer pressure and liquid volume dropped rapidly due to the decrease in core power. RCS temperature and pressure continue to decrease, until 370 seconds into the transient, when the liquid inventory in the steam generator not receiving auxiliary feedwater has been discharged through the safety valves. With this reduction in the heat sink, temperature and pressure continued to rise until approximately 1000 seconds when the remaining liquid mass in the two remaining steam generators, along with the mass added by the auxiliary feedwater system, became sufficient to dissipate the stored energy of the RCS.

At approximately 2500 seconds, boiloff of liquid inventory in the two steam generators receiving feed had decreased such that auxiliary feedwater flow was sufficient to just replenish liquid inventory discharged through the safety valves. RCS temperatures and pressurizer pressure and liquid volume increased until approximately 5100 seconds, at which time the decay heat generation was finally matched by the heat

removal of the auxiliary feedwater flow. Temperature, pressure, and liquid volume decrease for the remainder of the transient. A maximum RCS temperature of 598 °F, a maximum pressurizer pressure of 2570 psia, and a maximum pressurizer liquid volume of 1050 ft^3 were attained in the most limiting case.

The results of the case in which offsite power is not available are less limiting than the results of case with offsite power. This is expected, since the case with offsite power available also assumes continuous operation of the reactor coolant pumps, which contribute additional energy to the RCS for removal through the steam generators.

2.5.2.4 Conclusions

The UFSAR Section 15.2.8/15.2.9 loss of normal feedwater events were reanalyzed to evaluate the impact of reduced thermal design flow associated with extended steam generator tube plugging on analysis results. The analyses demonstrated that extended steam generator tube plugging levels do not adversely impact the ability of the auxiliary feedwater system to deliver adequate feedwater to prevent the relief of reactor coolant water through the pressurizer relief or safety valves, and to prevent system overpressurization. For both the case with offsite power assumed to be available and with offsite power unavailable, the feedwater flow rates required to provide adequate cooling were demonstrated to be well below actual deliverable pump flow rates.

2.5.3 Rod Bank Withdrawal a' Power Reanalysis (UFSAR Section 15.2.2).

The Rod Withdrawal at Power Accident has been reanalyzed to assess the impact of reduced minimum measured flow associated with extended SGTP. A statistical treatment of key analysis uncertainties was utilized in accordance with North Anna implementation of the methodology described in References (4),(5), and (6). A discussion of the analysis is presented in the following sections.

2.5.3.1 Accident Description

The uncontrolled rod cluster control assembly (RCCA) withdrawal at power is a postulated Condition II event initiated by operator action or control system malfunction. The transient is characterized by an increase in core heat flux resulting in a mismatch between core power generation and power removal by the steam generator. This power mismatch, which persists until the steam generator pressure reaches the relief or safety valve setpoint, causes an increase in the primary coolant temperature. The transient would result in violation of the core thermal limits if not terminated by either manual or automatic action. The reactor protection system is designed to terminate the transient prior to exceeding core thermal limits.

2.5.3.2 Method of Analysis

The rod withdrawal at power event was reanalyzed with the RETRAN (2),(3) system transient analysis code. All assumptions were consistent with or conservative with respect to those in the previously approved analyses (6),(5). The RETRAN code provided transient pressures, core inlet temperatures, heat fluxes and core flows which were used as input to a detailed thermal/hydraulic statepoint analysis using the COBRA (20) code. The WRB-1 correlation (7),(8) was used.

To fully evaluate the RWAP event, a wide range of initial plant conditions are analyzed to determine those which are most limiting. Permutations of the following conditions were analyzed:

1. Initial NSSS power levels of 100, 60, and 10% with minimum feedback for a wide range of reactivity insertion rates.

2. Initial NSSS power levels of 100, 60, and 10% with maximum feedback for a wide range of reactivity insertion rates.

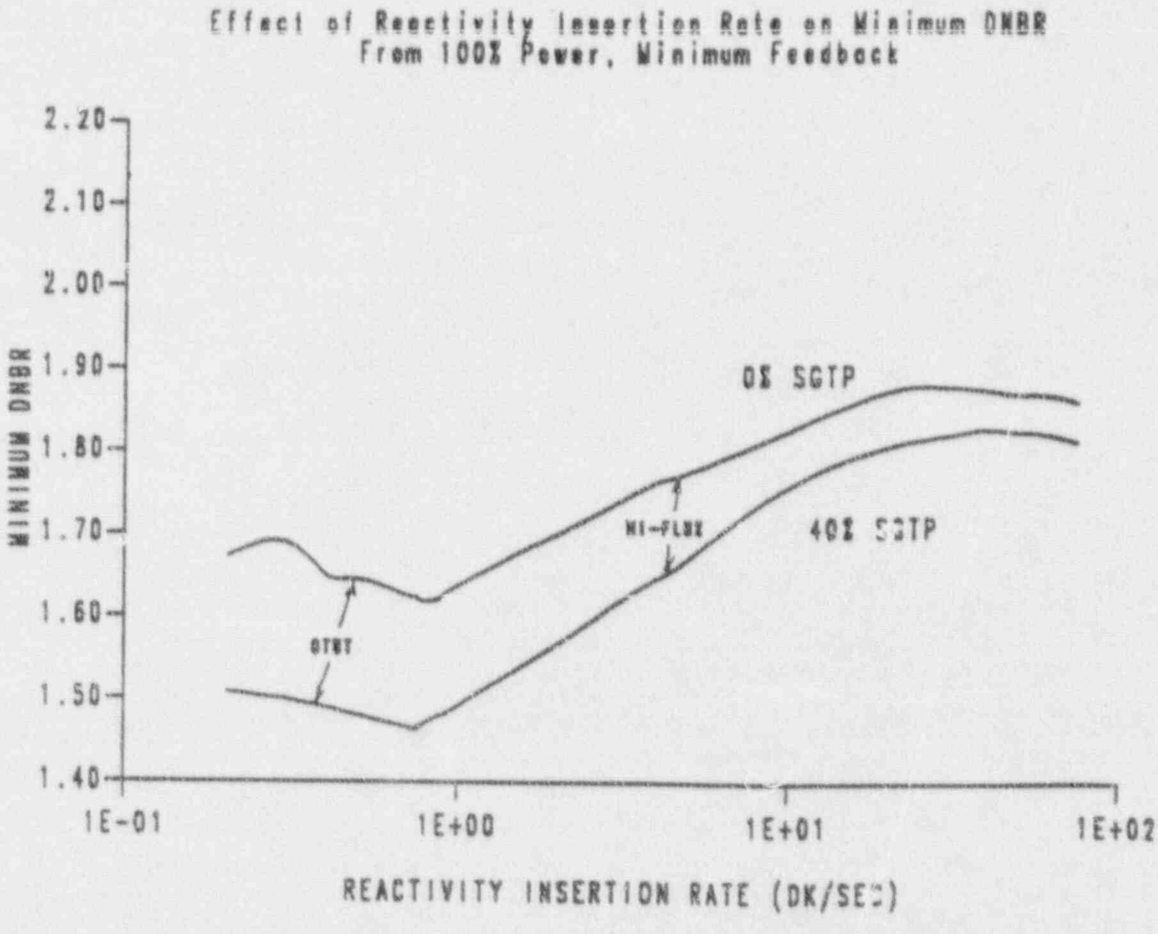
It is assumed in the analysis that the steam dump and rod control systems do not function during the RWAP event. However credit is taken for pressurizer PORV's and safety valves, steam generator atmospheric relief valves and safety valves, as well as pressurizer spray (full flow from both valves is assumed).

2.5.3.3 Results and Conclusions

The reanalysis of the rod withdrawal at power event demonstrated that the minimum DNBR will remain above the DNBR design limit for operation

with reduced minimum measured flow associated with extended steam generator tube plugging. As described in Sections 2.2 and 2.3, a penalty has been extracted from Core Thermal Limit retained DNBR margin to ensure that the current Technical Specifications OTΔT and OPΔT reactor trip setpoints continue to provide bounding core thermal limit protection. This analysis of the rod withdrawal at power event confirms that bounding Core Thermal Limit protection continues to be provided over a wide range of reactivity insertion rates and SGTP levels.

Figure 2.5.3-1, on the following page, presents the minimum RWAP DNBR result as a function of reactivity insertion rate. The upper graph (labelled 0% SGTP) is the analysis result assuming the current minimum measured flowrate. The bottom graph (labelled 40% SGTP) is the result from the revised analysis with reduced minimum measured flowrate. These results demonstrate that the combination of Overtemperature ΔT and high flux reactor trips act together to provide core DNB protection.



Effect of Reactivity Insertion Rate on Minimum DNBR
From 100% Power, Minimum Feedback
2.20
2.10
2.00
1.90
1.80
1.70
1.60
1.50
1.40
MINIMUM DNBR
0% SGTP
40% SGTP
HI-FLUX
OTDT
1E-01
1E+00
1E+01
1E+02
REACTIVITY INSERTION RATE (DK/SEC)

Figure 2.5.3-1

2.5.4 Complete Loss of Flow Reanalysis (UFSAR Section 15.3.4).

The Loss of Flow Accident (LOFA) has been reanalyzed to determine the impact of reduced minimum measured flow associated with extended SGTP. A statistical treatment of key analysis uncertainties was utilized in accordance with North Anna implementation of the methodology described in References (4),(5), and (6). A discussion of the analysis is presented in the following sections.

2.5.4.1 Accident Description

A complete loss of forced reactor coolant flow may result from a simultaneous loss of electrical power to all three reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of a LOFA is a rapid increase in the coolant temperature. This increase could result in DNB with subsequent fuel damage if the reactor is not promptly tripped. Reactor protection is provided by either the pump underfrequency or undervoltage trip function.

2.5.4.2 Method of Analysis

The LOFA was reanalyzed with the RETRAN transient analysis code (2), (3). All assumptions were consistent with or conservative with respect to those in the previously approved analyses. The RETRAN code provided transient pressure, core inlet temperature, heat flux and core flow which were used as input to a detailed thermal/hydraulic statepoint analysis performed with the COBRA (20) code. The WRB-1 correlation (7),(8) was

used. Two cases were analyzed: a complete loss of voltage at the RCP breakers and a 5.0 Hz/sec decay rate of the supply frequency (commonly referred to as the 'undervoltage'(UV) and 'underfrequency' (UF) cases, respectively). A +6 pcm/°F moderator temperature coefficient (MTC) was conservatively assumed although the actual full power MTC will be zero or negative. Delay times of 0.6 second and 1.2 seconds were assumed for the underfrequency and undervoltage trips respectively.

2.5.4.3 Results and Conclusions

The underfrequency trip LOFA was found to be the most limiting event. Transient DNBR's remained above the statistical DNBR design limit throughout the transient for both the UF and UV events. Figures 2.5.4-1 through 2.5.4-4 on the following pages present the result of the most limiting complete loss of flow case (UF). Graphs of RCS flow, pressurizer pressure, normalized core average heat flux and DNBR as a function of time are provided.

Underfrequency Case, RCS Flow vs Time

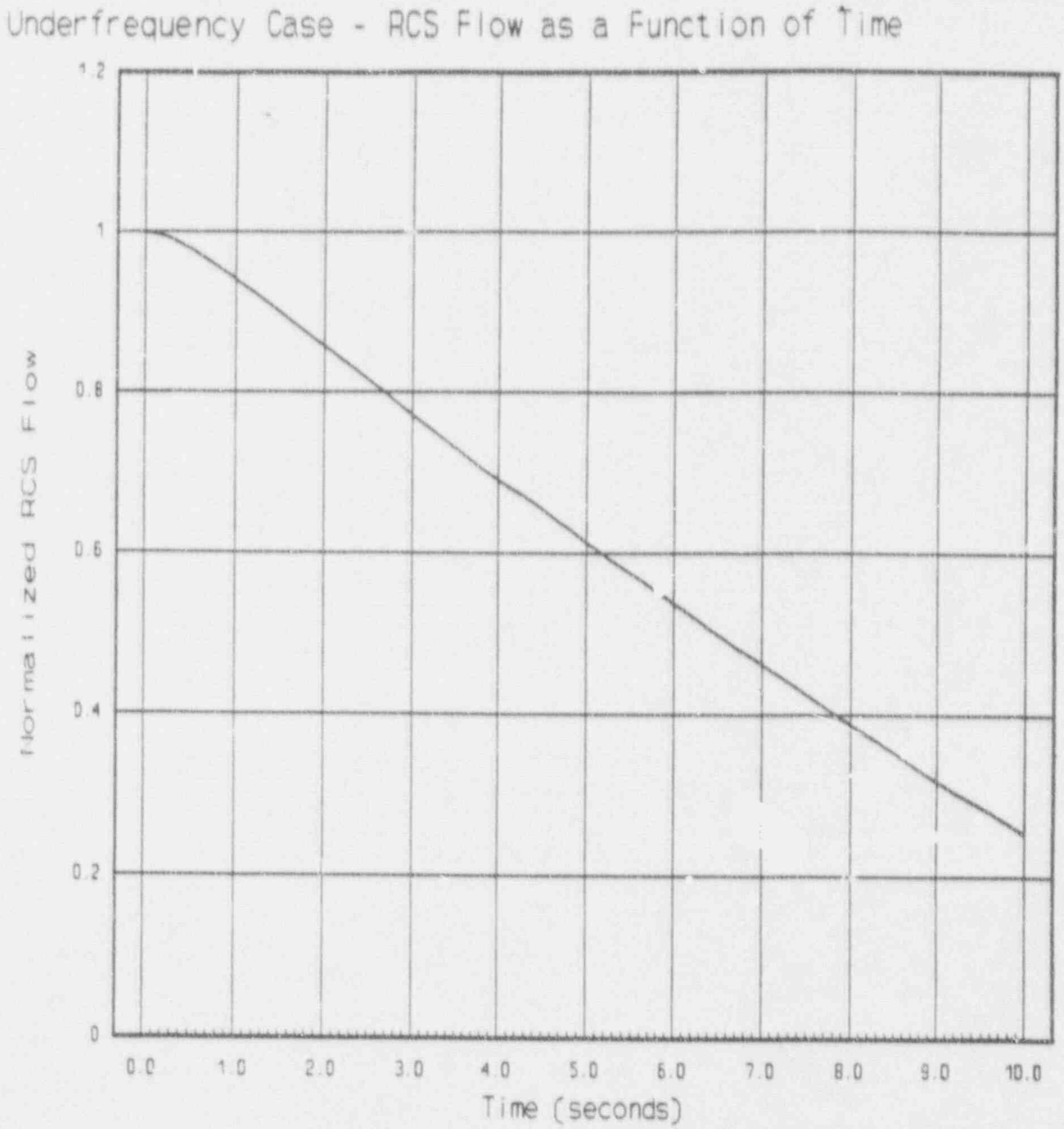


Figure 2.5.4-1

Underfrequency Case, RCS Pressure vs Time

Figure 2.5.4-2

Underfrequency Case, Heat Flux vs Time

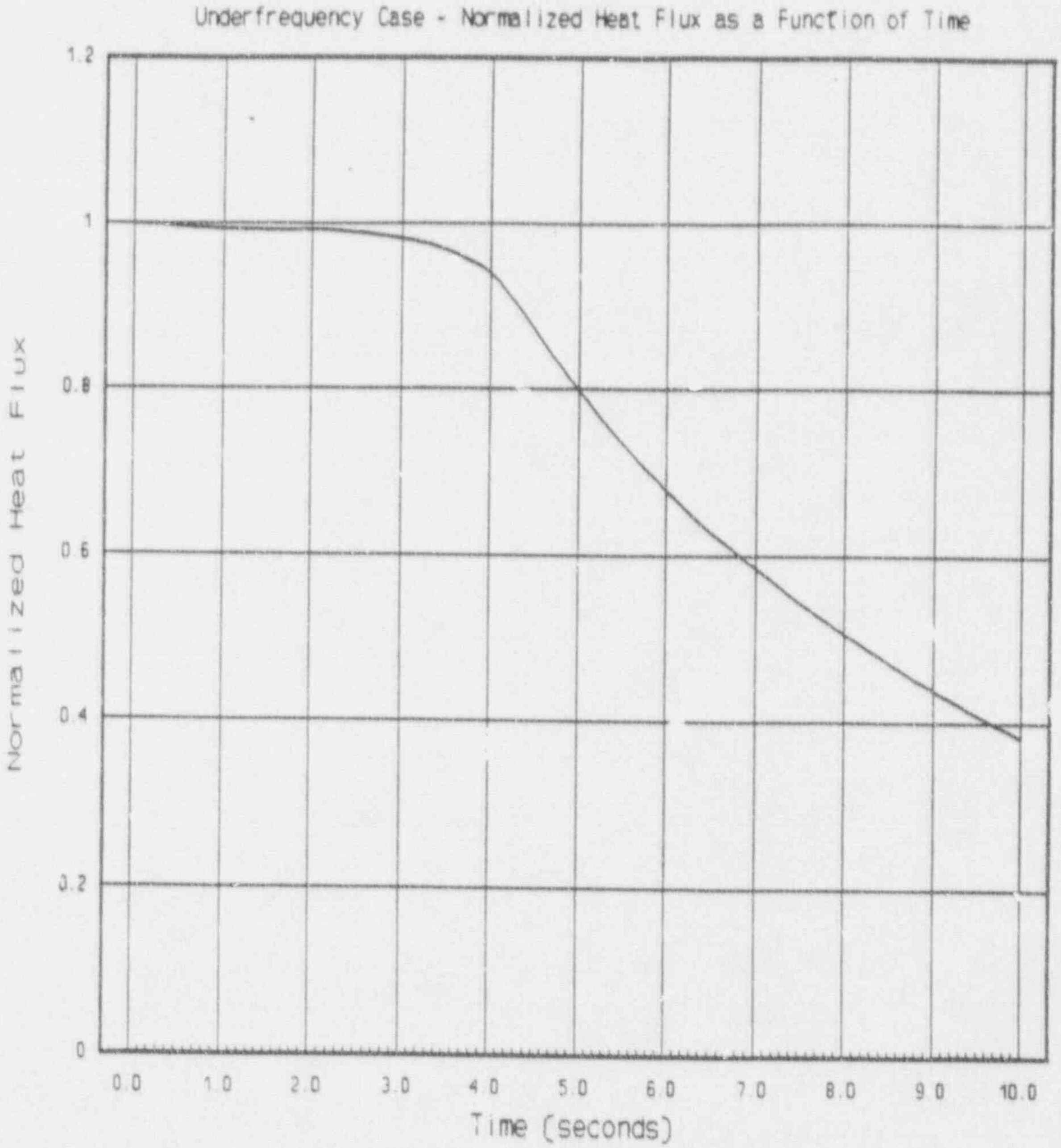
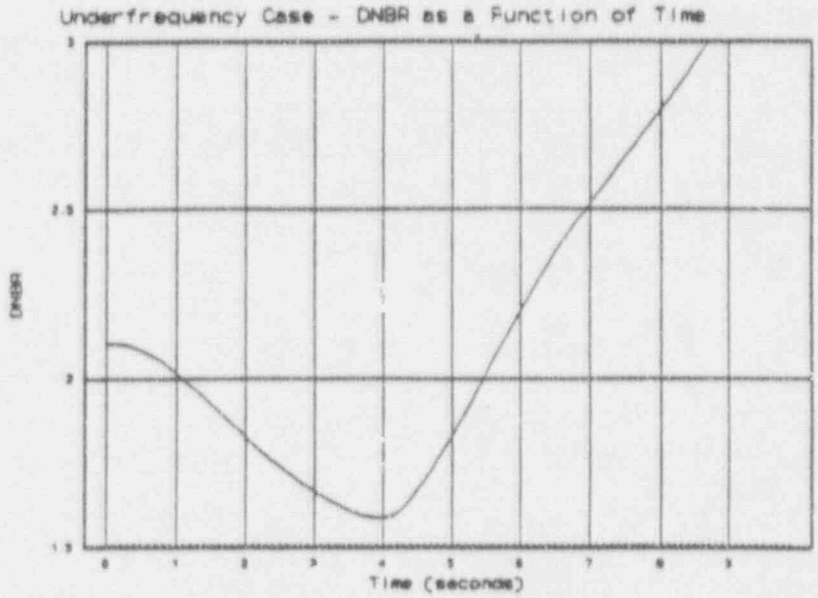


Figure 2.5.4-3

Underfrequency Case, DNBR vs Time



Underfrequency Case, DNBR vs Time - Enlarged View

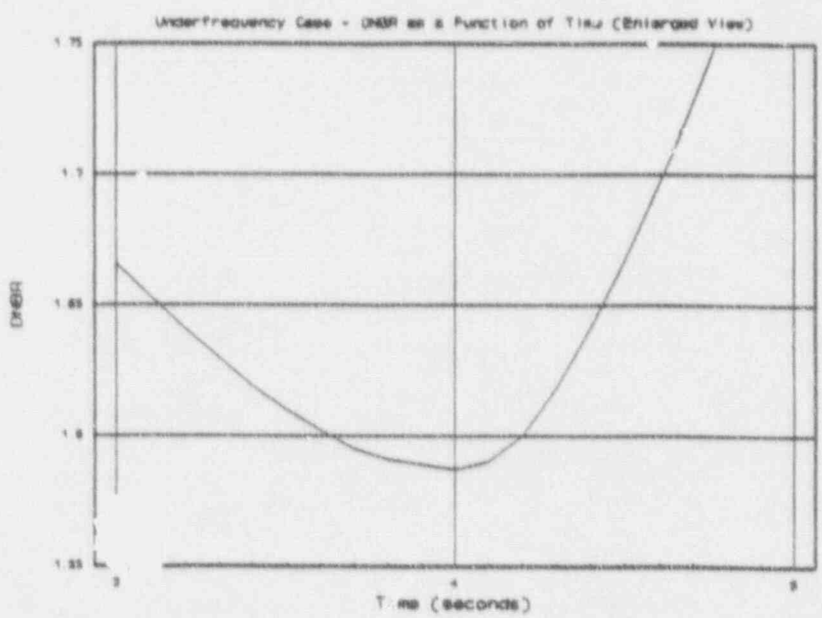


Figure 2.5.4-4

2.5.5 Locked Rotor/Sheared Shaft Reanalysis (UFSAR Section 15.4.4).

The Locked Rotor/Sheared shaft accident has been reanalyzed to quantify effects of reduced thermal design flow associated with extended SGTP. A discussion of the analysis is presented in the following sections.

2.5.5.1 Accident Description

The locked rotor event is defined as the instantaneous seizure of a reactor coolant pump rotor. Flow through the affected reactor coolant loop is rapidly reduced, leading to a reactor trip on low flow signal. Following reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the secondary side of the steam generators is reduced, first because the reduced flow results in a decreased tube-side film coefficient, and then because the reactor coolant in the tubes cools down while the shell-side temperature increases. Turbine steam flow is reduced to zero upon plant trip. The rapid expansion of the coolant in the reactor core, combined with the reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the reactor coolant system. The insurge into the pressurizer (a) compresses the steam volume, (b) actuates the automatic spray system, (c) opens the power operated relief valves, and (d) opens the pressurizer safety valves. The two power operated relief valves (PORVs) are designed for reliable operation and would be expected to function properly during

the accident. However, for conservatism, the pressure reducing effect of pressurizer PORVs and spray are not considered in the overpressure portion of the analysis.

2.5.5.2 Method of Analysis

The locked rotor/sheared shaft event was reanalyzed with the RETRAN system transient analysis code (2), (3). All assumptions were consistent with or conservative with respect to those in the currently applicable analysis. Previous analyses have shown that the results of the sheared shaft event are bounded by those of the locked rotor event. Therefore only the locked rotor case is considered here.

The single reactor coolant pump locked rotor incident is analyzed in two parts. First a peak pressure calculation is performed using conservative assumptions that tend to maximize the heat transfer from the fuel to the coolant. This calculation assumes that the fuel rods in the core do not experience departure from nucleate boiling (DNB). Second, the calculation is repeated to provide a conservative assessment of the fraction of the core experiencing DNB. The dose assessment is performed by conservatively assuming that if a rod experiences DNB, its cladding fails. The fraction of rods which are predicted to experience DNB is determined by an evaluation of $F_{\Delta H}$ versus fraction of fuel rods for each reload core. This process verifies for each reload core that the assumed percentage of fuel rod failure does not exceed the value of 13% assumed in the currently applicable offsite dose calculation (see UFSAR Section 15.4.4.2.7).

2.5.5.3 Results and Conclusions

For the peak pressure analysis case assuming 3% setpoint shift + 3% accumulation for the pressurizer safety valve, the peak RCS pressure (cold leg of a loop with pumps intact) remained well within the acceptance limit (110% of the RCS design pressure, or 2750 psia). Therefore, the overpressure results remain acceptable. Figure 2.5.5-1 on the following page presents the transient response of peak RCS pressure for the single locked rotor case analyzed.

For the core DNB case, the results showed that for the current Unit 1 operating Cycle, at the limiting time in core life, the criterion of <13% of fuel rods experiencing DNBR's less than the design limit continues to be met. Therefore the current offsite dose consequence analysis for this event remains bounding.

40% PLUGGING ANALYSIS
LOCKED RCP ROTOR
COLD LEG PRESSURE
(3% TOL. + ACCUM. MODEL)

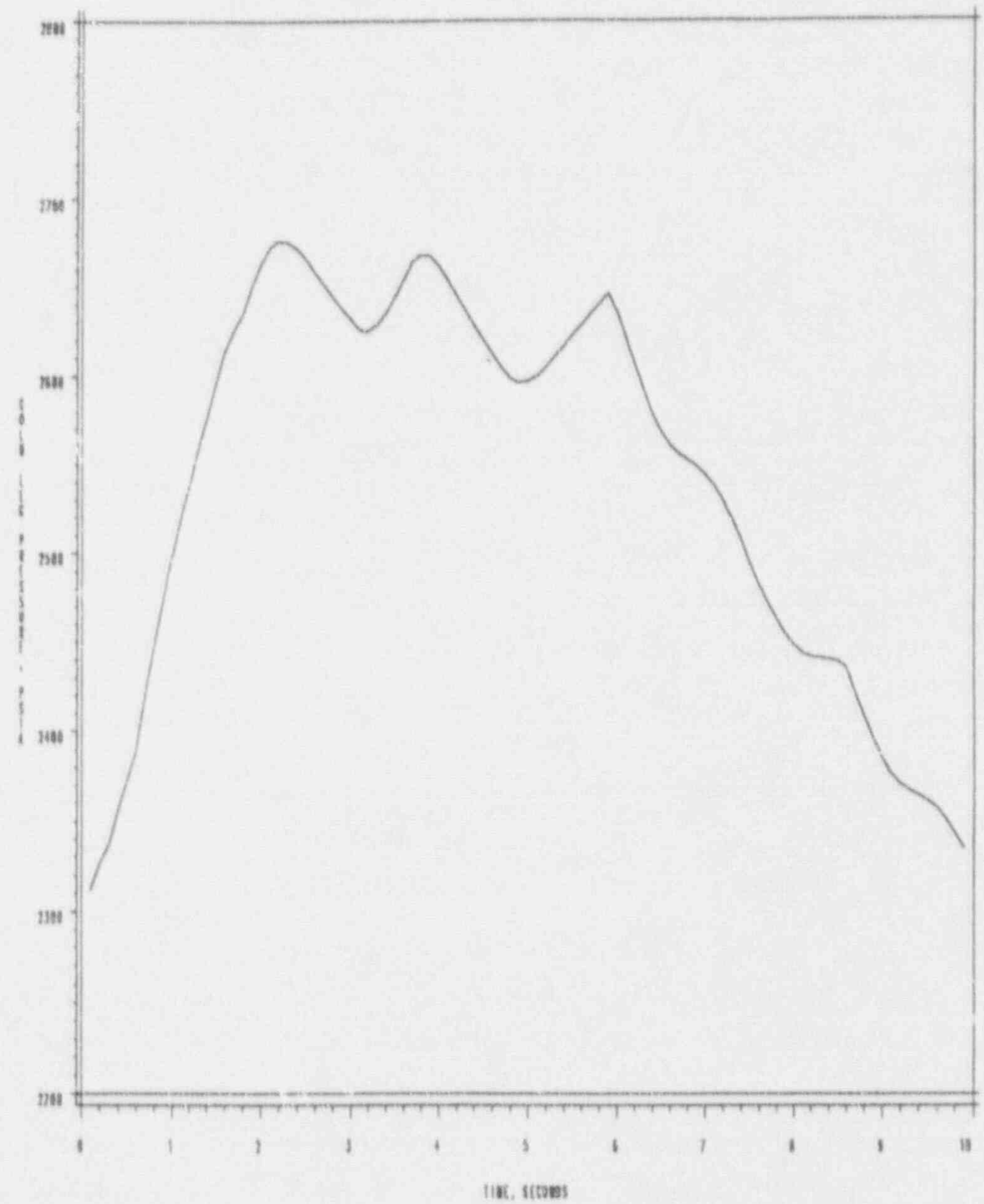


Figure 2.5.5-1

3.0 NSSS AND BALANCE OF PLANT SYSTEMS AND COMPONENTS

3.1 NSSS SYSTEMS AND COMPONENTS

Westinghouse Electric Corporation performed reviews of the following NSSS components and systems to confirm that operation within the proposed conditions remains in compliance with the applicable codes and standards.

- Reactor Vessel and Internals
- Control Rod Drive Mechanisms
- Main Loop Isolation Valves
- Reactor Coolant Pump and Motor
- Pressurizer
- Steam Generator
- Auxiliary Systems Components (tanks, valves, heat exchangers)
- Fluid Systems
- Reactor Protection and Control Systems

The key findings and summary of conclusions for each area are discussed below.

3.1.1 Reactor Vessel and Internals

An evaluation was performed to document the effects of operation at the proposed conditions upcn the reactor vessel structural and fatigue analysis. It was concluded that such operation will have no effect upon the North Anna Unit 1 reactor vessel stress report.

Assessments were also performed for various aspects of vessel internals design, including pressure losses, bypass flow, fluid temperatures, hydraulic lift forces and flow induced vibration. It was concluded that the internals system performance would remain within the

bounds determined in existing analyses for operation at the proposed conditions.

3.1.2 Control Rod Drive Mechanisms

The control rod drive mechanism structural integrity was reviewed for operation at the proposed conditions. This was performed by comparison with the original design parameters and determining the impact of the revised parameters on the applicable stress reports. The operating conditions are bounded by the original design pressure and temperature ranges.

3.1.3 Main Loop Isolation Valves

The loop isolation valve function and structural integrity were reviewed for operation at the proposed conditions. The conditions were found to have no impact on valve pressure boundary integrity or on valve operation. Therefore, the valves continue to comply with all applicable standards.

3.1.4 Reactor Coolant Pump and Motor

The coolant pump function and structural integrity have been reviewed for operation at the proposed conditions. The RCP hydraulics evaluation using revised flow/head values was found to be acceptable. The structural evaluation, which compared the new operating parameters to the original design specifications, concluded that the pump operating conditions are

bounded by the original design pressure and temperature ranges. Revised electrical loads were calculated for the pump motors for each of three limiting design conditions. No adverse impacts were found which would prevent the pump motor from performing its safety related function, i.e. coastdown.

3.1.5 Pressurizer

The pressurizer equipment specification and stress report have been evaluated for operation at the proposed conditions. The evaluation demonstrated that the operating and transient conditions are enveloped by the generic transients used in the analysis of the pressurizer components. Therefore, the existing stress report remains applicable.

3.1.6 Steam Generator

The steam generator conditions under the proposed operation have been evaluated for effects on thermal and hydraulic performance, U-bend vibration and structural integrity. A range of conditions corresponding to the reduced RCS flow and various levels of extended SGTP were evaluated. Specific design attributes studied were moisture carryover, hydraulic stability, U-bend vibration and structural integrity of key components. The results of these evaluations indicate that all steam generator design aspects continue to comply with all applicable acceptance criteria for operation within the range of proposed conditions.

3.1.7 Auxiliary Systems Components (tanks, valves, heat exchangers)

Operation at the proposed conditions remains within the bounds of parameters assumed in the existing analyses for these components. Therefore, there is no effect upon the auxiliary NSSS equipment.

3.1.8 Fluid Systems

Review of the Reactor Coolant (RCS), Residual Heat Removal (RHR), Chemical and Volume Control (CVCS) and Safety Injection (SI) systems were performed to confirm that operation at the proposed conditions remains in compliance with applicable acceptance criteria. It was concluded that each system continues to meet required acceptance criteria.

3.1.9 Reactor Protection and Control Systems

An evaluation was performed to assess the impact of reduced minimum measured flow associated with extended SGTP upon operation of the reactor control and protection systems. It was concluded that operation at the proposed conditions will require no changes in nominal control or protection actuation setpoints and that each system will continue to perform its required functions.

3.2 BALANCE OF PLANT SYSTEMS AND COMPONENTS

Stone and Webster Engineering Corporation (SWEC) has evaluated the effects of operating North Anna Unit 1 with reduced RCS flow and extended

SGTP upon the balance of plant systems and components. The changes of significance for this assessment involve reductions in RCS flow, RCS volume, steam temperature and steam pressure. Engineering evaluations have been performed to demonstrate that these parameter changes and resulting effects on plant systems and components will be bounded by existing analyses and will continue to meet applicable design criteria.

These major balance of plant design areas were evaluated:

- Accident Analyses
- Balance of Plant (BOP) Systems and Components
- Class I Piping
- Electrical Distribution System

The key findings and summary of conclusions for each area are discussed below.

3.2.1 Accident Analyses

The loss of coolant accident is the design basis event which is analyzed to confirm several aspects of containment and safeguards system design. Existing analyses for peak containment pressure, containment depressurization time, and net positive suction head (NPSH) for spray and safety injection pumps were evaluated for operation under the proposed RCS conditions. Analyses of postulated breaks of various RCS branch lines in the reactor cavity, SG cubicle and pressurizer cubicle were also reviewed for the proposed conditions. The results of the assessment concluded that the existing analyses will remain bounding for operation at the proposed conditions.

3.2.2 Balance of Plant (BOP) Systems and Components

A revised plant heat balance was prepared to reflect the proposed conditions. The BOP systems were reviewed utilizing the heat balance to determine any effects on system operation, flow, pressure, temperature and heat load. The systems which were reviewed are listed below.

- Main Steam System
- Extraction Steam System
- Auxiliary Steam System
- Condensate System
- Feedwater System
- Feedwater Heaters
- Component Cooling System
- Service Water System
- Circulating Water System
- Auxiliary Feedwater System
- Bearing Cooling System
- Moisture Separator/High Pressure Heater Drains
- Low Pressure Heater Drains
- Steam Generator Blowdown

For each system, the proposed conditions were assessed by comparison with the design conditions incorporated into the existing analysis of system design. It was concluded that operation at the proposed conditions will remain bounded by existing analyses of the BOP systems and components, and each will continue to perform its design function in accordance with applicable acceptance criteria.

3.2.3 Class I Piping

The review of pipe stress and support analyses addressed the effects of the proposed conditions on RCS loop piping deflection profiles. The aspects of interest are changes in end displacement boundary conditions for primary and secondary side branch piping and changes in UFSAR design margins for equipment supports. At the proposed conditions, it was concluded that the resulting changes are within the envelope of current normal operating temperatures for which the piping has been designed.

3.2.4 Electrical Distribution System

Potential impact of operation at the proposed conditions was assessed for key plant electrical distribution system components. No adverse effects were identified which would prevent these components from performing their design functions.

4.0 CONCLUSIONS

A review of the accident analysis presented in UFSAR Chapter 15 has demonstrated that a reduction in minimum measured flowrate for North Anna Unit 1 to 275,300 gpm is accommodated by current analysis margins or by the assessment of a penalty against available retained DNBR margin for all accidents. Explicit reanalyses were performed for the following events to confirm the adequacy of current analysis margins:

- Loss of Normal Feedwater
- Loss of External Electrical Load
- Uncontrolled Control Rod Bank Withdrawal at Power
- Complete Loss of Reactor Coolant Flow
- Locked Reactor Coolant Pump Rotor

The analyses showed that all of the acceptance criteria previously established in the UFSAR continue to be met for each reanalyzed event. This conclusion will be reinforced by continued verification that core physics characteristics for operation with a reduced RCS flowrate associated remain within the envelope established by the current reload safety evaluation.

The current Engineered Safety Features and Reactor Protection System setpoints set forth in the Unit 1 Technical Specifications have been demonstrated to provide adequate plant protection at the reduced flow condition.

The current Core Thermal Limits have been verified to remain bounding for operation with the new RCS flow rate.

A review of the NSSS design transients; NSSS fluid and control systems; reactor control and protection systems; NSSS primary components (including thermal and structural effects); and steam generator thermal/hydraulic performance has been performed. It was concluded that NSSS systems and components will continue to meet applicable acceptance criteria for operation with the reduced design flow rates and the associated steam generator tube plugging levels.

An engineering evaluation has also been performed to assess the impact of reduced flow and tube plugging on the existing containment integrity analyses (including the impact on Net Positive Suction Head-NPSH) of engineered safeguards pumps) and containment subcompartment integrity analyses. The existing analyses were shown to remain bounding.

A balance of plant systems review shows continued acceptable performance under the reduced RCS flow/ extended tube plugging condition.

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ATTACHMENT 4

10 CFR 50.92
NO SIGNIFICANT HAZARDS CONSIDERATION
EVALUATION

VIRGINIA ELECTRIC AND POWER COMPANY

10 CFR 50.92
No Significant Hazards Consideration Evaluation

The proposed changes to the North Anna Power Station Unit 1 Technical Specifications has been evaluated against the criteria described in 10 CFR 50.92 and it has been determined that the proposed amendment to the operating license involves no significant hazards consideration. The basis for this determination is as follows:

North Anna Power Station Unit 1 is currently involved in a mid-cycle steam generator inspection outage. An extensive eddy current inspection of the North Anna Unit 1 steam generator tubes is being performed using very conservative analysis guidelines and plugging criteria. As such, a substantially increased number of tubes are expected to be plugged.

As required by Technical Specifications 3.2.5 and 4.2.5.2, North Anna Unit 1 performs reactor coolant system (RCS) flow rate measurements once per fuel cycle. The North Anna Unit 1 safety analyses are based in part on verifying, via the Technical Specifications surveillance, that the Reactor Coolant System (RCS) total flow rate is greater than or equal to 284,000 gallons per minute (gpm). The additional steam generator tube plugging anticipated during the current mid-cycle inspection outage increases the likelihood of violating this Technical Specifications requirement. Therefore, safety analyses and evaluations have been performed which support an approximate 3% reduction in the RCS total flow rate limit to 275,300 gpm.

The proposed Technical Specifications changes implement a reduced total flow rate requirement which is intended to bound future measured flow values and any required steam generator tube plugging until steam generator replacement. The changes will allow the unit to continue to operate with the expected increase in RCS loop resistance caused by increased steam generator tube plugging levels and ensure that the required safety margins for core cooling and accident analysis are maintained.

The attached safety analysis documents a review of the accident analyses presented in the UFSAR. In summary, this review has demonstrated that a reduction in minimum measured flowrate for North Anna Unit 1 to 275,300 gpm is accommodated by current analysis margins or by the assessment of a penalty against available retained DNBR margin for all accidents. Explicit reanalyses were performed for the following events to confirm the adequacy of current analysis margins:

- Loss of Normal Feedwater
- Loss of External Electrical Load
- Uncontrolled Control Rod Bank Withdrawal at Power
- Complete Loss of Reactor Coolant Flow
- Locked Reactor Coolant Pump Rotor

The analyses showed that all of the acceptance criteria previously established in the UFSAR continue to be met for each reanalyzed event. This conclusion will be reinforced by continued verification that core physics characteristics for operation with a reduced RCS flow rate remain within the envelope established by the current reload safety evaluation.

The current Engineered Safety Features and Reactor Protection System setpoints set forth in the Unit 1 Technical Specifications have been demonstrated to provide adequate plant protection at the reduced flow condition.

The current Core Thermal Limits have been verified to remain bounding for operation with the reduced minimum RCS flow rate.

A review of the Nuclear Steam Supply System (NSSS) design transients, NSSS fluid and control systems, reactor control and protection systems, NSSS primary components (including thermal and structural effects), and steam generator thermal / hydraulic performance has been performed. It was concluded that the NSSS systems and components will continue to meet applicable acceptance criteria for operation with the reduced design flow rates and the associated steam generator tube plugging levels.

An engineering evaluation has also been performed to assess the impact of reduced flow and tube plugging on the existing containment integrity analyses (including the impact on net positive suction head of the engineered safeguards pumps) and containment subcompartment integrity analyses. The existing analyses were shown to remain bounding.

In addition, a balance of plant systems review shows continued acceptable performance under the reduced RCS flow / extended tube plugging condition.

Virginia Electric and Power Company has reviewed these proposed Technical Specifications changes relative to operation of North Anna Unit 1 with reduced minimum RCS total flow rate and determined that the proposed changes do not involve a significant hazards consideration as defined in 10 CFR 50.92. The basis for this determination is that this change:

1. Does not involve a significant increase in the probability or consequences of an accident previously evaluated.

   The impact of the reduced minimum measured RCS flow rate on operating characteristics, and accident analyses which support Unit 1 operation, have been fully assessed and documented in the attached safety evaluation. The proposed reduction to the Technical Specifications minimum measured RCS flow rate does not impact either equipment or operating conditions that are considered in determining the probability of occurrence for any of the UFSAR Chapter 15 accident analyses. The proposed reduction of minimum measured RCS flow rate has the potential to increase accident analysis consequences. However, the results of the reanalyses show that the design limits are met. Therefore, the consequences of an accident previously evaluated remain unchanged.

2. Does not create the possibility of a new or different kind of accident from any accident previously evaluated.

   The proposed change to the Technical Specifications does not involve modifications to any of the existing equipment. The impact of the proposed reduced minimum measured RCS flow rate on North Anna Unit 1 operating characteristics, and accident analyses which support Unit 1 operation, have been fully assessed and documented in the attached safety evaluation. The proposed reduction to the Technical Specifications minimum measured RCS flow rate does not create any new or different accident initiators, so no unique accident possibility is created. Therefore, the proposed Technical Specifications change would not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does not involve a significant reduction in a margin of safety.

   The proposed amendment has been analyzed and the Technical Specifications continue to ensure that adequate reactor coolant system total flow is maintained. The impact of the proposed reduced minimum measured RCS flow rate on North Anna Unit 1 operating characteristics, and accident analyses which support Unit 1 operation, have been fully assessed and documented in the attached safety evaluation. The analyses and equipment evaluations show that the applicable design limits are met. Therefore, there is no significant reduction in the margin of safety.

Based on the above significant hazards consideration evaluation, Virginia Electric and Power Company concludes that the activities associated with this proposed Technical Specifications change satisfies the no significant hazards consideration standards of 10 CFR 50.92(c) and, accordingly, a no significant hazards consideration finding is justified.