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SAFETY REVIEW FOR HOPE CREEK GENERATING STATION SAFETY/RELIEF VALVE TOLERANCE ANALYSES

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**IMPORTANT NOTICE REGARDING
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SUMMARY

This report documents the analyses performed for Hope Creek Generating Station to support the relaxation of the tolerances for the opening setpoints of the safety/relief valves from the current ± 1% value to ± 3%. The evaluation addresses the safety concerns associated with these proposed changes.

The turbine trip without bypass, the most limiting abnormal transient event for Hope Creek in Cycle 7, was re-evaluated at opening nominal setpoints ± 3% in conjunction with one SRV out-of-service. Results show that with tolerance on the setpoints relaxed to ±3% and with one SRV inoperable, there is no impact on the fuel thermal limits.

Vessel overpressure analyses for the most limiting pressurization event, the MSIV closure with flux scram indicates that vessel pressure remains within the ASME Upset Code limit of 1375 psig (with a conservative margin of more than 40 psi) at the increased setpoint tolerances as well to pressures up to 1250 psig. A single upper limit for vessel pressure was not determined as a re-evaluation of the containment loads indicated a very limiting amount of margin. For this reason, maximum allowable pressure is determined on an individual valve basis, as is listed in Table 7-1.

An anticipated transient without scram (ATWS) analysis for the MSIV closure event was performed, and it was found that vessel pressurization remains well within the ATWS design criteria of 1500 psig for the maximum vessel overpressure.

A loss of coolant accident evaluation revealed that increase in setpoint tolerances would have negligible or no impact on these analyses. Analyses performed on the high pressure emergency core cooling systems indicate that these systems can perform their design functions under the new setpoint tolerances. A markup of the Technical Specifications, which incorporates changes suggested by the information included in this report, is provided.

<u>The Revision 1 of this report is issued to document changes to the identification of sections in the report which contains GE-proprietary information, shown within brackets</u> [ ] .

1.0 INTRODUCTION

1.1 PURPOSE

The purpose of this report is to present the results of an evaluation of the updated Safety/Relief Valve (SRV) performance requirements at the Hope Creek Generating Station (HCGS). The performance changes are selected to minimize the impact on plant operations from potential pressure relief system related problems due to SRV setpoint drift. Public Service Electric and Gas Company (PSE&G) has requested that the changes be evaluated to support relaxing the surveillance requirement tolerance from the current ±1% to ±3% for the nominal SRV setpoints.

The current performance requirements for the Hope Creek SRVs are discussed in Section 1.3. Each of the present performance requirements pertinent to this analysis are identified, as well as the associated limitations and the remedial actions for exceeding the limit. Section 1.4 discusses the proposed performance requirement changes, the associated limits and the analyses required to support each proposed change. A comparison of the present and proposed performance requirements is shown in Table 1-1.

1.2 BACKGROUND

The nuclear pressure relief system at Hope Creek consists of SRVs located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The valves provide the following primary functions:

(1) Overpressure safety/relief operation. SRVs open automatically against spring restraint to limit the vessel pressure excursion during a postulated pressurization transient event.

(2) Depressurization operation. The Automatic Depressurization System (ADS) functions to open selected SRVs automatically via a pilot air system. It is considered to be part of the Emergency Core Cooling System (ECCS) for events involving small breaks in the reactor vessel process barrier.

(3) Low-Low-Set (LLS) operation. Following initial opening and closure of SRVs, two SRVs operate in the LLS mode opening and closing at pressures lower than the other SRVs to reduce the amount of cycling on the non-LLS SRVs.

1.3 PRESENT PERFORMANCE REQUIREMENTS

1.3.1 SRV Setpoint Tolerances

From Reference 1, the current SRV and LLS configuration and nominal opening setpoint for Hope Creek is as follows:

Safety/Relief Valves:	4@ 1108 psig
	5@ 1120 psig
	5@ 1130 psig
Low-Low-Set Valves	1@ 1017 psig
	1@ 1047 psig

A narrow ±1% tolerance band on the SRV nominal setpoints which was adopted to develop the Technical Specifications stems from an acceptance criterion defined by the American Society of Mechanical Engineers (ASME) for in-service plant testing. Section 3/4.4.2 of the current Technical Specifications states that the allowable setpoint errors for each SRV shall be ±1%. The ASME has since revised the criterion for demonstrating valve operational readiness from ±1% to ±3% (Reference 2)

The ±1% tolerance applies to several limitations which have to be addressed if these tolerances are exceeded. These limitations are as follows:

(1) Technical Specification 3/4.4.2 delineates that the SRVs be operable within ±1% of the nominal setpoint. In addition, this section of the Technical Specifications specifies the requirements associated with removal and testing of the valves.

(2) Licensing basis analyses have been performed assuming opening pressures are 1% above the nominal setpoints. For Hope Creek, if opening pressures for the SRVs are greater than 1% above the nominal setpoint, then the plant could potentially operate in an unanalyzed condition. Such a condition warrants a Licensee Event Report (LER) and a safety evaluation.

(3) Valve refurbishment and the removal of additional valves from the plant for testing are necessary if valve opening pressures are demonstrated to be beyond the limitations of Technical Specification 3/4.4.2 (±1% of the nominal SRV settings).

(4) If surveillance testing demonstrates that the opening pressures are not within ±1% of the nominal setpoint, setpoint adjustment to ±1% tolerance is required prior to returning the valves to service.

Consequently, valve opening setpoint drift to > ±1% of the nominal setpoint causes each of the remedial actions above to be taken, thereby increasing valve surveillance testing costs, adding to the number of reportable events and consuming utility manpower. Although the ±1% tolerance is specified in the Technical Specifications and has been used in plant safety evaluations, it does not represent the limiting setpoint required to ensure plant safety. Several BWRs have experienced SRV setpoint drift in excess of the Technical Specification limitations. In each case safety evaluations were performed on a cycle specific basis, demonstrating that setpoint drift did not compromise plant safety. The consequences of valves opening setpoint drift can be minimized by increasing the setpoint tolerance assumed in licensing analyses and resultant plant operating limits.

1.3.2 SRVs Out of Service

The current reload licensing bases for Hope Creek include the assumption of 1 SRV declared out of service (OOS) (Reference 3). The vessel overpressure analysis documented in the cycle-specific reload licensing submittal supports operation with 1 SRV OOS.

1.4 PROPOSED PERFORMANCE REQUIREMENT CHANGES

This section discusses the effect of each set of the proposed performance requirement changes and the analyses necessary to support the changes. The present and proposed SRV performance requirement changes are shown in Table 1-1.

The ASME has expanded the acceptance criterion for SRVs, performance testing from ±1% to ±3% per Reference 2. Consequently, as long as the maximum valve opening pressure remains below the nominal + 3% range, the plant will still be operating within analyzed conditions, and the valves can be considered capable of performing their de-pressurization function.

The acceptance criterion defines the range of expected in-service performance of a valve. Beyond this criterion, valve refurbishment is required and additional valves must be removed from the plant for testing. The increased tolerance on the acceptance criterion potentially reduces the number of valves that will exceed the in-service performance testing requirements, thus reducing the cost of valve surveillance testing.

Prior to placing new or refurbished valves in service, the valve opening setpoints must be adjusted to be within ±1% of the nominal settings. This re-installation of valves within a ±1% tolerance ensures that there is margin to the ±3% in-service testing criterion for opening pressure. In this manner, valve integrity and the benefits of the increased tolerance to reduce surveillance requirements are maintained from cycle to cycle.

Table 1-1
COMPARISON OF PRESENT TO PROPOSED PERFORMANCE REQUIREMENTS

Performance Requirement	Present Limit	New Limit
1. Opening pressure up to which the SRVs are capable of performing their intended function (i.e., operable).	± 1%	± 3%
2. Opening pressure up to which licensing basis analyses have been performed.	± 1%	± 3%
3. Tolerance beyond which valve refurbishment and additional valve testing is required as demonstrated by surveillance testing.	± 1%	± 3%
4. Tolerance on the as-left SRV setting prior to the valve being returned to service.	± 1%	± 1%

2.0 ANALYSIS APPROACH

This section identifies the analyses which may be affected by the proposed valve performance requirement changes. The analyses performed in the following sections assume that the plant operating parameters and the core design (Ref. 1) are consistent with the HCGS Reload 6 Cycle 7 licensing calculations (Ref. 3).

The following safety and regulatory concerns are identified as potentially being affected as a result of the SRV setpoint tolerance increase to ±3%:

1. Vessel overpressurization.
2. Thermal limits during abnormal operational occurrences.
3. ECCS/loss of coolant accident (LOCA) performance.
4. High pressure emergency systems performance.
5. Containment pressures, temperatures, and loads.
6. Anticipated transients without scram (ATWS) mitigation capability.
7. Effects on plant Technical Specifications.

Each applicable safety and regulatory concern implied in the above listed items was reviewed to determine the acceptability of SRV Technical Specification opening pressures ± 3%. Discussions are presented in the sections indicated in Table 2-1.

Table 2-1
ANALYSES PRESENTED IN THIS REPORT

Item	Section	Result
Vessel Overpressurization	3.0	Acceptable Upper Limit Pressure 1250 psig
Thermal Limits	4.0	Acceptable for abnormal operational occurrences (Ref. 3)
ECCS/LOCA Performance	5.0	Acceptable (Ref. 7)
High Pressure Emergency Systems Performance	6.0	Acceptable
Containment Evaluations	7.0	Acceptable up to Analytical Limits detailed in Table 7-1
ATWS Mitigation	8.0	Acceptable Max. vessel pressure 1425 psig
Effects on Technical Specifications	9.0	Acceptable Some changes-See Attachment

3.0 VESSEL OVERPRESSURE ANALYSIS

The ASME code requires peak vessel pressures to be less than the upset transient limit of 1375 psig during transient events. The limiting overpressure event for HCGS is the Main Steamline Isolation Valve (MSIV) Closure with Flux Scram event (Ref. 3). The reactor is shutdown by the backup high neutron flux scram due to the vessel pressurization and the following collapse of voids.

The greatest challenge to the ASME upset code limit is provided by assuming that all the Safety/Relief Valve opening setpoints have drifted upward to +3% above the nominal trip setpoint, coincident with one SRV out-of-service (SRV OOS), leaving 13 SRVs operable. To bound potential SRV drift beyond the ±3% range of nominal trip setpoint and to support potential SRV opening setpoint increase for simmer margin considerations, the analysis assumes a single upper limit setpoint and applies that to the current HCGS SRV configuration.

3.1 OVERPRESSURE ANALYSIS ASSUMPTIONS

The following assumptions and initial conditions were used in analyzing the MSIV closure with flux scram for HCGS:

(1) Initial core thermal power at 102% of rated.
(2) Initial core flow at 105% of rated.
(3) [ ]
(4) Credit taken for the available SRVs in the safety mode.
(5) A single upper limit setpoint of 1250 psig which is the design pressure for SRVs is used, with 13 SRVs operable (the lowest safety mode setpoint SRV OOS for design basis considerations).

The GE [ ] , was used to obtain the system response and peak vessel pressure. [ ]. The use of this computer code is consistent with the HCGS reload licensing analysis methodology (Ref. 5).

3.2 OVERPRESSURE ANALYSIS RESULTS

The overpressure analysis results are applicable to HCGS Cycle 7. The reactor response with the SRV safety mode opening setpoints at the single upper limit of 1250 psig is shown in Figure 3-1. The event is initiated as the MSIVs begin to close. As a result of the reactor vessel isolation, the reactor pressure rises rapidly and collapses the voids, which in turn increases the neutron flux, causing the reactor to scram on high neutron flux. The system pressure then reaches the recirculation pump trip setpoint of 1071 psig. The reduction in coolant flow increases the void fraction in the core and accelerates the power reduction process. The vessel pressure continues to rise until the SRV opening pressures are reached and subsequent SRV actuations terminate the pressurization transient.

With a single upper limit setpoint of 1250 psig and 13 SRVs available out of a total of 14, the calculated peak vessel pressure at the bottom of the reactor vessel is 1331 psig, thus providing a margin of 44 psi to the ASME upset code limit of 1375 psig. Therefore, with respect to the vessel overpressurization requirement, HCGS can operate with the safety mode of SRV configuration at a +3% tolerance setting and one design basis SRV OOS.

Table 3-1 shows the resultant peak vessel pressure for the MSIV closure flux scram event analyzed and Figure 3-1 shows the time histories of key parameters during this transient event. The generic result in Reference 6 and the HCGS cycle 7 reload result in Reference 3 are included in Table 3-1 for purposes of comparison.

Table 3-1
MSIV CLOSURE WITH FLUX SCRAM EVENT ANALYSIS RESULTS

Power/Flow (% of Rated)	S/RV Configuration	Peak Neutron Flux (% NBR)	Peak Average Heat Flux (% NBR)	Peak Steamline Pressure psig	Peak Vessel Bottom Pressure psig
102/105	1250 psig 13 SRVs	437	126	1314	1331
102/100 (1)	1250 psig 10 SRVs 3 SSVs				1324
102/105 (2)	Nom.+1% 14 SRVs	437	126	1203	1232

Note: (1) Generic result in Reference 6.

(2) HCGS unit Cycle 7 reload analysis (Ref. 3) with ±1% setpoint tolerance range.

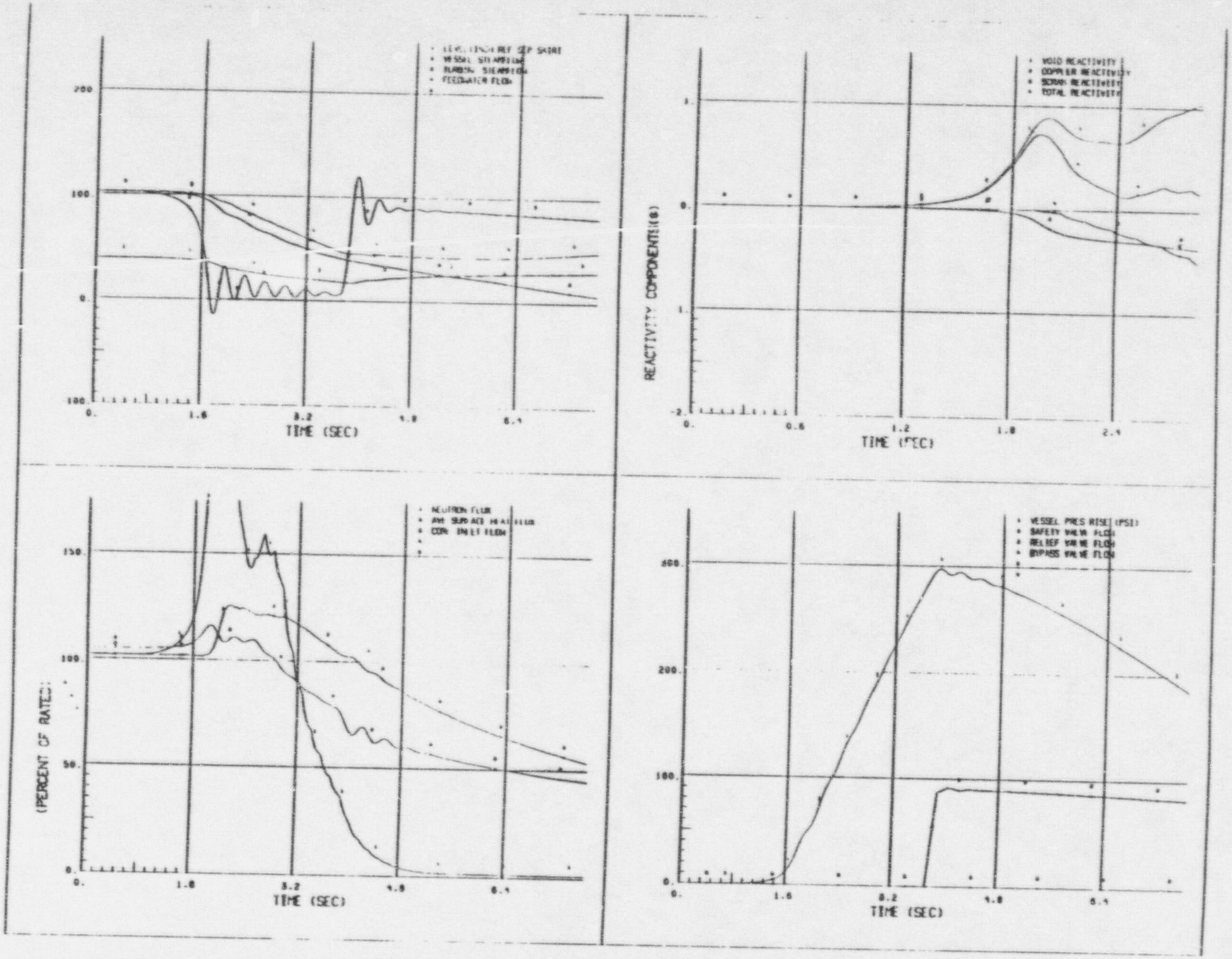

Figure 3-1 MSIV Closure Flux Scram Event, 102P/105F, Single Upper Limit of 1250 psig, 13 SRVs in Service

4.0 THERMAL LIMITS

Important in the study to increase the tolerance on SRV opening setpoints are the effects on the reactor fuel of pressurization transients. Surveys were done, therefore, to determine the transients which have the greatest impact on fuel thermal limits. The most limiting abnormal operational occurrence (AOO) for Hope Creek Cycle 7 was found to be the turbine trip without bypass (Ref. 3). This event was used to determine the most operationally limiting thermal limits for the core. The minimum critical power ratio (MCPR) is the most significant thermal limit for evaluation.

Reference 3 provides results of computer-simulated transients to support Cycle 7 plant operation. Figures 4-1 and 4-2 provide resulting transient traces for initial conditions of 100% power/105% core flow. Peak values of average surface heat flux indicate the most limiting MCPR value. Traces of vessel pressure and relief valve steam flow are also shown. It should be noted that the heat flux, and therefore MCPR, peaks at a time prior to peaking of vessel pressure and opening of SRVs. Times for occurrence of MCPR and first opening of SRVs are presented in Table 4-1.

As opening pressure setpoints of SRVs are increased to higher pressures, as is done to analyze effects of increasing positive tolerance on the setpoints, peak pressures and relief valve opening occur later relative to the time of occurrence of the MCPR. Increases of SRV opening setpoint pressures, therefore, have no impact on MCPR because the opening has no effect on occurrences before the SRVs open. Hence, for opening pressure setpoints greater than the nominal setpoint, increase of SRV opening setpoint pressure tolerance to +3% and establishment of an upper limit will not impact fuel thermal limits considerations.

For a decrease in the SRV opening setpoint pressure of 3%, the actuation of the valves would occur at an earlier time than for the +3% tolerance case. However, as noted in Table 4-1, openings of the valves still occur after the MCPR. Therefore, for the same reason as presented for openings at the nominal setpoint + 3%, MCPR will not be impacted by SRVs opening at nominal setpoint pressures - 3%. Even if one considers that the relief valve opening occurs at such a short time after the MCPR that the occurrence of these events could fall within some margin of error for the calculations, it may be observed that even if relief valves begin to open just before MCPR occurs, the effect would be to relieve vessel pressure, thereby reducing reaction rates and heat generation by the fuel and relieving MCPR concerns. Hence, it can be considered that extending the setpoint tolerance from -1% to -3% does not impact projected cycle thermal margins/limits.

Table 4-1
CHRONOLOGY FOR THERMAL LIMITS EVALUATION FOR TURBINE TRIP WITHOUT BYPASS

	Time after Initiation of Event (sec)	
	With RPT[1]	Without RPT[1]
Occurrence of MCPR [3]	1.229	1.220
First SRV Opening at Nominal Setpoint [2]	1.814	1.801
SRV Nominal Setpoint Minus 3% [2]	1.253	1.238

Notes:

(1) RPT = Recirculation Pump Trip.

(2) From ODYN code.

(3) From GETAB code.

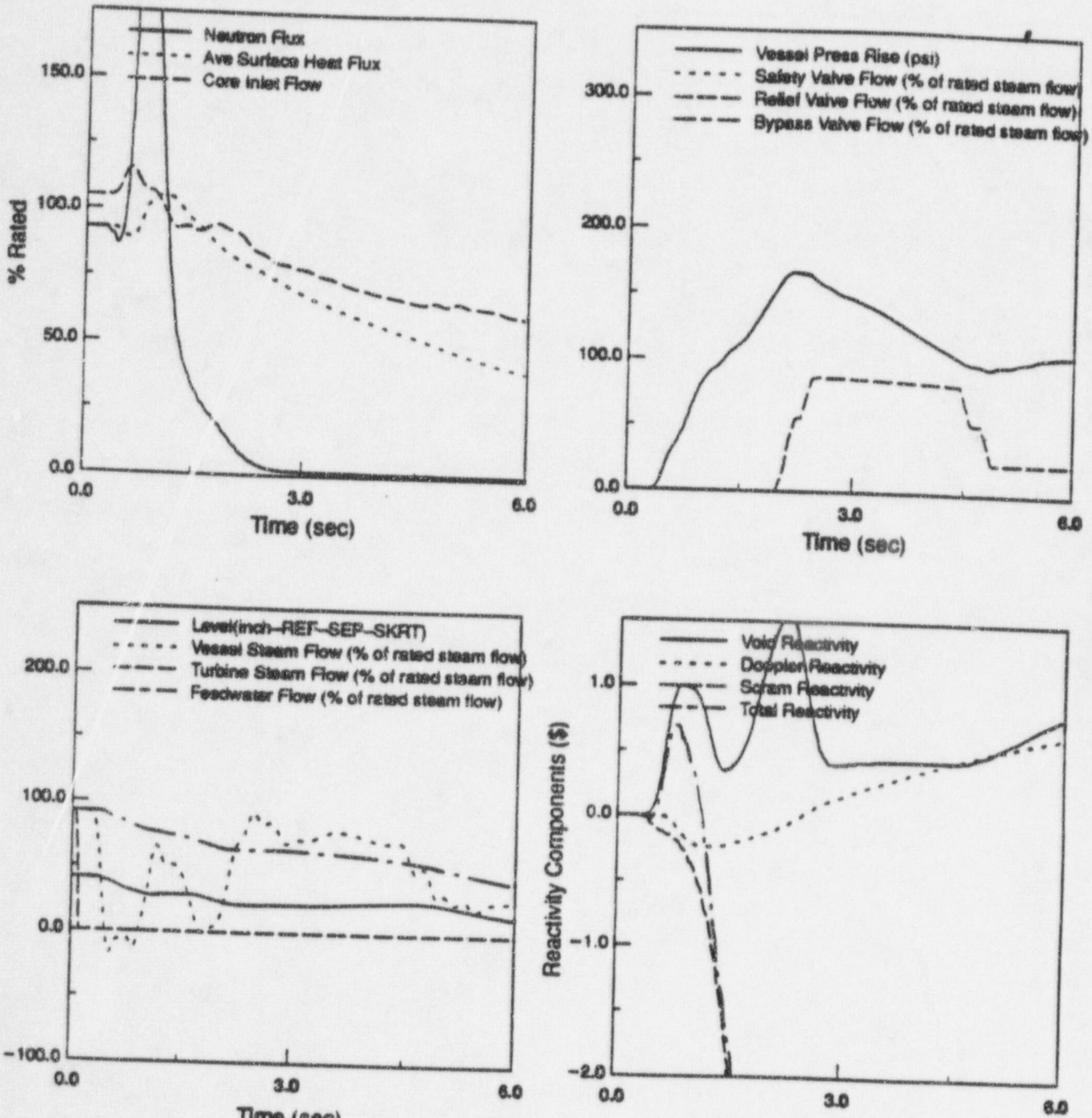

Figure 4-1
Plant Response to Turbine Trip without Bypass
(BOC 7 to EOC 7 100% Power/105% Core Flow with RPT)

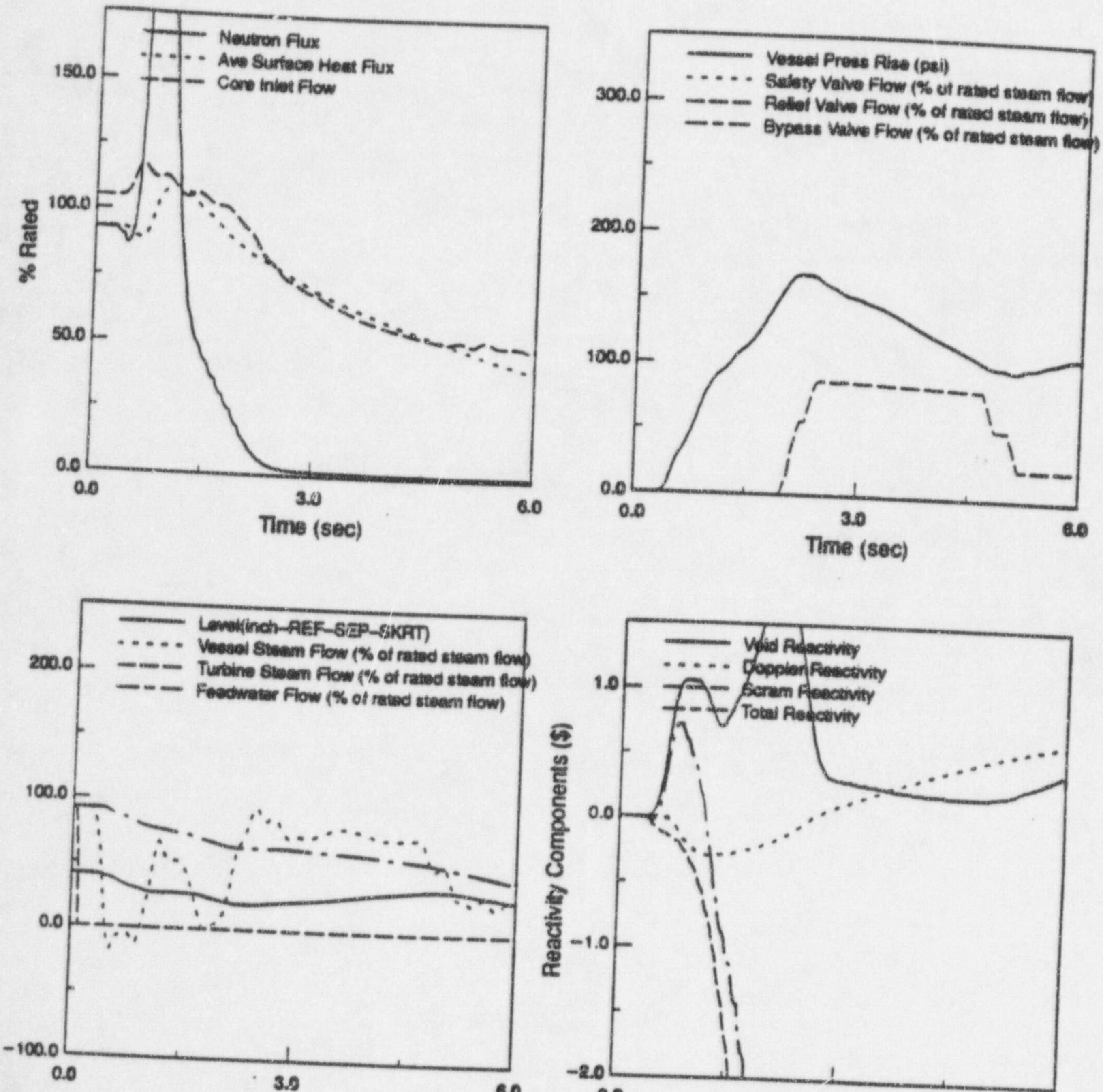

Figure 4-2
Plant Response to Turbine Trip without Bypass
(BOC 7 to EOC 7 100% Power/105% Core Flow with RPT Out of Service)

5.0 ECCS/LOCA PERFORMANCE EVALUATION

The Hope Creek LOCA analysis (Ref. 7, Sec. 6.3)) has been reviewed to determine the impact of a combination of increase in the SRV opening pressures and SRV OOS condition on the Emergency Core Cooling System (ECCS) performance. The SRV opening pressures were assumed to drift up to 3% above the nominal trip setpoint and one SRV was considered inoperable. The ECCS is designed to protect the fuel integrity during postulated LOCAs by limiting the calculated peak cladding temperature (PCT) to below the requirements of 10CFR50.46, i.e., to less than 2200 degrees F. A change in the SRV opening pressures and/or SRV OOS can only affect the pipe break events for which SRV actuations occur. These events were then evaluated to determine the impact of valve actuations at a potentially higher setpoint. The intent of these evaluations was to demonstrate that the limiting break (yielding the highest PCT) remains unaffected by these changes and that the effect on the other lower PCT breaks would not cause them to become the limiting break.

The following postulated pipe break scenarios were considered:

- Limiting break LOCA (licensing basis event)
- Small break LOCA
- Steamline break outside the containment.

5.1 LIMITING BREAK LOCA

Based on a review of the results of the Reference 7 analyses, the limiting break for Hope Creek is the design basis accident (DBA) recirculation line break. For this type of event, the reactor vessel depressurizes very rapidly through the break. Because the vessel immediately depressurizes, no SRV actuation will occur. Therefore, an increase in the SRV opening setpoint does not have any adverse impact on the limiting break analysis results. This conclusion is also applicable to the operating condition with one SRV OOS.

5.2 SMALL BREAK LOCA

For a postulated small break LOCAs, the vessel depressurizes more slowly than in the design basis LOCA, and upon vessel isolation is expected to pressurize (Reference 3). For such an event, a few SRV actuations may occur. However, as the event progresses and inventory is depleted, the low reactor water level Automatic Depressurization System (ADS) setpoint will be reached and, if the vessel water level has not recovered by the time the ADS timer (approximately 2 minutes) has expired, it will actuate, opening several SRVs. The vessel then rapidly depressurizes, permitting low pressure ECCS to inject into the reactor vessel and restore the normal water level. The inventory lost is significantly less than the DBA LOCA, resulting in a lower PCT (1694°F) than that of the limiting large break LOCA event (2046°F) (Reference 7, Table 6.3-3).

For a postulated small break LOCA, increased SRV actuation setpoints 3% above the nominal values will result in a slight delay in the SRV actuation after MSIV closure. Reference 6 analyzes and bounds the small break LOCA up to an SRV opening setpoint upper limit of 1250 psig for all BWRs. The inventory loss from the vessel with valve actuations at a higher than design basis system pressure will be essentially unchanged because the valves will open later, fewer valves are likely to open, and subsequent cycling of the valves will not be significantly different. Therefore, at the time of ADS initiation, the difference in the vessel inventory for the case with SRVs at the current tolerance setpoint and increased tolerance setpoint is negligible. As a result, PCTs for the small break LOCAs involving SRV actuation will not change significantly. Since these small break events are not limiting in comparison to the large break, the impact on the LOCA licensing basis for Hope Creek is insignificant.

5.3 STEAMLINE BREAK OUTSIDE THE CONTAINMENT

In this type of event, a double-ended guillotine break of one main steamline is assumed to occur outside of the containment. The reactor vessel is completely isolated after 5.5 seconds upon closure of the main steam isolation valves (Reference 7, section 15.6.4). As a result, the break flow also terminates and the reactor vessel pressure increases rapidly. The system pressure is relieved by multiple SRV actuations which will slowly deplete vessel inventory. Subsequent vessel pressure reduction may be provided by manually or automatically with the ADS valves. Prior to ADS initiations this event is very similar to an isolation event with the core remaining covered. The ADS actuation causes a significant loss of vessel inventory which may result in core uncovery. The steamline break outside the containment for Hope Creek is less severe than the recirculation line break event however and the corresponding PCT is well below the value calculated for the large break LOCA (Reference 7, section 6.3).

If the SRVs are assumed to actuate at the increased setpoints, the SRVs will open later than in the design analyses. Again, the net inventory loss is not significantly changed because the SRVs will open later and fewer valves will be likely to open if the drift is extreme (e.g. 15.31% drift on valve E during RF06 testing). Subsequent cycling of one or two valves will not produce any changes in the inventory loss as the valves return to their normal range of operation or to their pre-designated low-low-set (LLS) setpoints after first actuation. The PCT for this event occurs after the reactor is depressurized using ADS. This is significantly after the SRVs have returned to operation in their normal range of pressures and for this reason there is no PCT change from the licensing basis event.

6.0 HIGH PRESSURE SYSTEM PERFORMANCE

The purpose of this section is to evaluate the impact of the proposed safety relief valve opening setpoint tolerance relaxation on the high pressure system performance at the Hope Creek Generating Station. The following systems are included in the evaluation:

- High Pressure Coolant Injection (HPCI)
- Reactor Core Isolation Cooling (RCIC)
- Standby Liquid Control System (SLCS)

6.1 HIGH PRESSURE COOLANT INJECTION SYSTEM PERFORMANCE EVALUATION

The most significant impact of the SRV setpoint tolerance program on the HPCI system is the increased reactor pressure due to the increase in the SRV setpoint tolerance. For HCGS, the HPCI system was originally designed to provide injection into the reactor pressure vessel up to a reactor pressure of 1120 psig (101 % of the nominal setpoint for the lowest group of valves, 1108 psig). With the setpoint tolerance relaxation program, the SRV safety setpoint tolerances are being increased from ±1 % to ± 3%. This change increases the maximum reactor pressure for HPCI system injection by 21 psi, from 1120 psig to 1141 psig.

The ability of the HPCI pump to inject its design flow rate into the reactor vessel is not affected by this change. The pump dynamic head required for system injection with the SRV setpoint tolerance change is within the original design capability of the pump and system. The introduction of the HPCI flow split modification during the plant design phase resulted in a reduction in the required system operating pressures. The original HPCI system design for HCGS was based on injection into the reactor through one of the core spray system headers. The flow split modification diverted 3100 gpm of the HPCI flow to the feedwater sparger through a new line, while maintaining 2500 gpm to the core spray header. This design change reduced the HPCI system flow losses and maximum required pump discharge pressure by 53 psi. No changes were made to the equipment or to the system design specifications as the result of this modification.

Since this margin is more than sufficient to compensate for the increased reactor pressure with the increase in SRV setpoint tolerance, no further modifications or changes are required for the system to meet its injection requirements.

6.1.1 System Function and Requirements

The HPCI system, an ECCS component, is designed to provide sufficient core cooling and prevent excessive fuel cladding temperature in the event of a small break LOCA that does not depressurize the reactor quickly enough to permit timely operation of the low pressure ECCS. The HPCI system accomplishes this function by injecting coolant makeup water into the pressure vessel using a turbine driven pump. The HPCI system can also serve as a backup to the Reactor Core Isolation Cooling system to maintain the nuclear boiler in the standby condition in the event the vessel becomes isolated from the main condenser and the feedwater makeup flow. The HPCI system is designed to inject coolant makeup water at its designed flow of 5600 gpm within 35 seconds after receipt of the initiation signals. Some of the steam being generated by the reactor is used to drive the turbine.

6.1.2 Inputs and Assumptions

The following values constitute the present design of the HPCI system:

System Flow Rate	=	5600 gpm
Reactor Operating Pressure Range	=	200 to 1120 psig
System Injection Time	=	35 seconds

Changes to the HPCI system will be based upon maintaining the same system flow rate and injection time at the new maximum system operating pressure. Table 6-1 lists the parameters used to evaluate the effect of the SRV setpoint tolerance relaxation upon the HPCI system performance.

6.1.3 System Evaluation

Design Flow Rate

Injection Flow: The original design basis resulted in a system flow rate of 5600 gpm. This flow rate requirement does not change for the SRV setpoint tolerance increase.

Steam Flow: The maximum turbine steam flow rate shown for Mode A on the System Process Diagram will decrease slightly with the increase in maximum reactor pressure. This is because the data provided in the Process Diagram was based on the original pump head and flow requirements.

Design Temperature and Pressure

The design temperatures for those portions of the system interfacing with the reactor will not increase under the conditions for this analysis. For the steam supply lines and the turbine, the original design temperature was formulated using the reactor design temperature of 575°F. For the segment of pump discharge piping interfacing with the feedwater line, the original design temperature was based on the maximum feedwater temperature. With the SRV setpoint tolerance change, the temperature of this line will not change.

The design pressure for those portions of the system interfacing with the reactor will not increase under this program. For the steam supply lines and the turbine, the original design pressure was formulated using the reactor design pressure of 1250 psig. The peak pressure for the pump and the pump discharge lines will not change since the maximum rated speed for the pump does not change.

System Injection Time

The HPCI system design basis injection time is 35 seconds from onset of the reactor water low level or high drywell pressure conditions, until the injection rate into the reactor reaches its design value. There is no change in the system injection time since the maximum rated speed for the pump has not changed and there is no change in the pump total dynamic head (TDH).

6.1.4 Component Evaluation

System components were evaluated by comparing the current design temperatures and pressures with the expected system operating temperatures and pressures with the increased SRV setpoint tolerances. This examination demonstrated that the expected operating values are bounded by the current design. Therefore, the individual system components will be subjected to temperatures and pressures that are within the current design.

Main Pump

The pump operating parameters will remain within the original pump design envelope with this program. No change in the pump maximum rated speed or pump discharge pressure is necessary.

Turbine

The turbine will be operating within its original design envelope, having the capability to operate at the increased steam supply pressure. No change in the turbine maximum rated speed is necessary.

Valves

The following valves are connected to the HPCI system and need to be reviewed for any potential impact resulting from the proposed SRV setpoint tolerance relaxation:

Reactor pressure:

E41-F001	Turbine Steam Admission Valve
E41-F002 & F003	Turbine Steam Supply Isolation Valves
E41-F100	Turbine Steam Supply Isolation Valve - Bypass Valve
E41-F028 & F029	Steam Line Drain System Isolation Valves
E41-F054	Steam Line Drain, Steam Trap Bypass Valve

Pump Discharge Pressure:

E41-F012	Minimum Flow Valve
E41-F007	Pump Discharge Valve
E41-F006	Discharge Valve to Core Spray Line
E41-F059	Cooling Water Supply Valve
E41-F105	Discharge Valve to Feedwater Line
E41-F008 & F011	Full Flow Test Return Valves

While continued compliance with NRC Generic Letter 89-10 is expected for some of these valves which are motor-operated, this needs to be confirmed by PSE&G.

6.1.5 Interfacing Systems Evaluation

Systems interfacing with the HPCI are identified in the HPCI System Piping and Instrument Diagram. The Primary Containment, Condensate and Condenser, Reactor Water Cleanup, Radwaste, and Standby Gas Treatment systems interface with the HPCI system, but do not have significant changes to the system interfaces.

Main Steam System

The maximum steam flow rate required from the main steam system to drive the HPCI turbine will decrease slightly. With the SRV setpoint tolerance relaxation, the maximum steam supply pressure for system operation increases by 21 psi from 1120 psig to 1141 psig.

Feedwater System

The maximum pressure at the HPCI interface with the Feedwater supply line will increase by 21 psi during system operation, given the SRV setpoint tolerance relaxation. For the segment of HPCI pump discharge piping interfacing with the feedwater line, the original design temperature was based on the maximum feedwater temperature. With this proposed SRV setpoint tolerance change the temperature of this line will not increase.

Core Spray System

The maximum pressure at the HPCI interface with the Core Spray System supply line will increase by 21 psi during system operation, given the SRV setpoint tolerance relaxation. For the segment of HPCI pump discharge piping interfacing with the CS System line, the original design temperature was based on the maximum reactor temperature. With this proposed SRV setpoint tolerance change the temperature of this line will not increase.

Electrical Power - Safety Related

For the HPCI System, the increase in the motor operated valve electrical loads resulting from operation at higher differential pressures, has been estimated to have a negligible impact on the plant electrical distribution systems. This is based on the assumption that the existing valve operators and motors are able to meet the SRV setpoint tolerance relaxation program conditions.

Leak Detection System

The HPCI System includes instrumentation that measures the steam flow rate in the turbine steam supply line as a means of detecting a break in the system piping. The instrumentation indicates if an isolation should occur. The analog trip instrumentation setpoints do not need to be re-evaluated since the steam flow rates for Mode A operation have decreased slightly. The maximum steam flow rate at the original reactor pressure of 1120 psig remains as a valid operating point for the system.

6.1.6 HPCI Performance for LOCA Events

An increase of the SRV opening pressures will not impact HPCI performance for the design basis LOCA events since system injection can be assured at the increased reactor pressure.

6.1.7 Conclusion

The HPCI System was found to have the capability to deliver the required flow of 5600 gpm at the increased reactor pressure resulting from relaxation of the SRV setpoint tolerance. This tolerance relaxation program also does not impact the design of those system components directly impacted by the increased reactor pressure, including the valves. This is because the proposed setpoint increase remains below the maximum permitted valve design pressure by the ASME Boiler & Pressure Vessel Code Specifications.

The HPCI system valves that are impacted by the increased reactor pressure will require re-evaluation for operability at the increased operating pressures with the higher SRV setpoint tolerances. The specified maximum differential pressure values for the HPCI steam supply and pump discharge valves shall be readjusted accordingly to reflect the increased SRV safety setpoints and higher system operating pressures.

The HPCI turbine is verified to be capable of operating at the increased steam supply pressures and temperatures with this program. The HPCI pump was originally designed with sufficient head to meet the new injection pressure requirements while still maintaining an adequate system operating margin.

The impact of this SRV setpoint tolerance relaxation on the remainder of the system components was determined to be negligible because of the very small increase in operating pressure and/or temperature.

6.2 REACTOR CORE ISOLATION COOLING SYSTEM PERFORMANCE EVALUATION

The most significant impact of the SRV setpoint tolerance program on the RCIC system is the increased reactor pressure due to the increase in the SRV setpoint tolerance. For HCGS, the RCIC system was originally designed to provide injection into the reactor pressure vessel up to a reactor pressure of 1120 psig (101 % of the nominal setpoint for the lowest group of valves, 1108 psig). With the setpoint tolerance relaxation program, the SRV safety setpoint tolerances are being increased from $\pm 1\%$ to $\pm 3\%$. This change increases the maximum reactor pressure for RCIC system injection by 21 psi, from 1120 psig to 1141 psig.

The ability of the RCIC pump to inject its design flow rate into the reactor vessel is not affected by this change. The pump dynamic head required for system injection with the SRV setpoint tolerance change is within the original purchased capability of the pump and system. Since this installed margin is sufficient to compensate for the increased reactor pressure with the increase in setpoint tolerance, no further modifications or changes are required for the system to meet its injection requirements.

6.2.1 System Function and Requirements

The RCIC system, classified as a power generation system, is designed to maintain the reactor vessel water level above Level 1 in the event of a transient event which results in the loss of all feedwater flow or reactor isolation. The system is also designed to allow for complete shutdown by maintaining sufficient water inventory until the reactor is depressurized to a level where the shutdown cooling mode of the residual heat removal (RHR) system can be placed into operation. The RCIC System accomplishes this function by injecting coolant makeup water into the pressure vessel with a turbine driven pump.

The RCIC System is designed to inject coolant makeup water at its designed flow of 600 gpm within 30 seconds after conditions require system initiation. Some of the steam being generated by the reactor is used to drive the turbine.

6.2.2 Inputs and Assumptions

The following values constitute the present design of the RCIC system:

System Flow Rate	=	600 gpm
Reactor Operating Pressure Range	=	150 to 1120 psig
System Injection Time	=	30 seconds

Changes to the RCIC system will be based upon maintaining the same system flow rate and injection time at the new maximum system operating pressure. Table 6-2 lists the parameters used to evaluate the effect of the SRV setpoint tolerance relaxation upon the RCIC system performance.

6.2.3 System Evaluation

Design Flow Rate

Injection Flow: The original design basis resulted in a system flow rate of 600 gpm. This flow rate requirement does not change for the SRV setpoint tolerance increase.

Steam Flow: The maximum steam flow rate required from the main steam system to drive the RCIC turbine will increase from 33,000 lbm/hr to 33,700 lbm/hr. The original turbine steam flow rate was obtained from the System Process Diagram. The steam flow rate for operation at the higher reactor pressure was based on this original flow rate and the calculated increase in pump horsepower. The RCIC turbine has sufficient pressure margin at the higher reactor pressures to compensate for the expected increase in steam line pressure drop with the higher steam flow rates.

Design Temperature and Pressure

The design temperatures for those portions of the system interfacing with the reactor will not increase under the conditions for this analysis. For the steam supply lines and the turbine, the original design temperature was formulated using the reactor design temperature of 575°F. For the segment of pump discharge piping interfacing with the feedwater line, the original design temperature was based on the maximum feedwater temperature. With the SRV setpoint tolerance change, the temperature of this line will not change.

The design pressure for those portions of the system interfacing with the reactor will not increase under this program. For the steam supply lines and the turbine, the original design pressure was formulated using the reactor design pressure of 1250 psig. The peak pressure for the pump and the pump discharge lines will not change since the maximum rated speed for the pump does not change.

System Injection Time

The RCIC system design basis injection time is 30 seconds from onset of the reactor water low level or high drywell pressure conditions, until the injection rate into the reactor reaches its design value There is no change in the system injection time since the maximum rated speed for the pump has not changed and the turbine acceleration rate is controlled electronically during startup.

6.2.4 Component Evaluation

System components were evaluated by comparing the current design temperatures and pressures with the expected system operating temperatures and pressures with the increased SRV setpoint tolerances. This examination demonstrated that the expected operating values are bounded by the current design. Therefore, the individual system components will be subjected to temperatures and pressures that are within the current design.

Main Pump

The pump will be operating within its original as built envelope for speed and pressure with this program. Vendor test data indicated the pump produced a TDH of 2860 feet at the rated speed of 4500 rpm during factory acceptance testing. No change in the pump maximum rated speed is necessary to achieve the required pump TDH wth the increse in SRV setpoint tolerance. Since the pump maximum rated speed does not increase there will be no increase in the peak pump discharge pressure at the shutoff head conditions, assuming normal control system tolerances. As a result, there is no increase in the system design pressure.

Turbine

The turbine will be operating within its original design envelope and has the capability to operate at the increased steam supply pressure. No change in the turbine maximum rated speed is necessary.

Valves

The following valves are connected to the RCIC system and need to be reviewed for any potential impact resulting from the proposed SRV setpoint tolerance relaxation:

Reactor Pressure:

E51-F045	Turbine Steam Admission Valve
E51-F007& F008	Turbine Steam Supply Isolation Valves
E51-F025 & F026	Steam Line Drain Valves
E51-F054	Steam Line Drain, Steam Trap Bypass Valve

Pump Discharge Pressure:

E51-F019	Minimum Flow Valve
E51-F012	Pump Discharge Valve
E51-F013	Discharge Valve to Feedwater Line

E51-F022	Full Flow Test Return Valve
E51-F046	Cooling Water Supply Valve

While continued compliance with NRC Generic Letter 89-10 is expected for some of these valves which are motor-operated, this needs to be confirmed by PSE&G.

6.2.5 Interfacing Systems Evaluation

Systems interfacing with the RCIC are identified in the RCIC System Piping and Instrument Diagram. The Primary Containment, Condensate and Condenser, Reactor Water Cleanup, Radwaste, and Standby Gas Treatment systems interface with the RCIC system, but do not have significant changes to the system interfaces.

Main Steam System

The maximum steam flow rate required from the main steam system to drive the RCIC turbine will increase from 33,000 lbm/hr to 33,700 lbm/hr. With the SRV setpoint tolerance relaxation, the maximum steam supply pressure for system operation increases by 21 psi from 1120 psig to 1141 psig.

Feedwater System

The maximum pressure at the RCIC interface with the Feedwater supply line will increase by 21 psi during system operation given the SRV setpoint tolerance relaxation. For the segment of RCIC pump discharge piping interfacing with the feedwater line, the original design temperature was based on the maximum feedwater temperature. With this proposed SRV setpoint tolerance change the temperature of this line will not increase.

Electrical Power - Safety Related

For the RCIC System, the increase in the motor operated valve electrical loads resulting from operation at higher differential pressures, has been estimated to have a negligible impact on the plant electrical distribution systems. This is based on the assumption that the existing valve operators and motors are able to meet the SRV setpoint tolerance relaxation program conditions.

Leak Detection System

The RCIC System includes instrumentation that measures the steam flow rate in the turbine steam supply line as a means of detecting a break in the system piping. The instrumentation indicates if an isolation should occur. The analog trip instrumentation setpoints need to be re-evaluated since the steam flow rates for Mode A operation have increased from 33,000 lbm/hr to 33,700 lbm/hr.

6.2.6 RCIC Performance for Isolation Events

An increase of the SRV opening pressures will not impact RCIC performance for the reactor isolation events since system injection can be assured at the increased reactor pressure.

6.2.7 Conclusion

The RCIC System was found to have the capability to deliver the required flow of 600 gpm at the increased reactor pressure resulting from relaxation of the SRV setpoint tolerance. This tolerance relaxation program also does not impact the design of those system components directly impacted by the increased reactor pressure, including the valves. This is because the proposed setpoint increase remains below the maximum permitted valve design pressure by the ASME Boiler & Pressure Vessel Code Specifications.

The RCIC system valves that are impacted by the increased reactor pressure will require re-evaluation for operability at the increased operating pressures expected with the higher SRV setpoint tolerances. The specified maximum differential pressure values for the RCIC steam supply and pump discharge valves shall be readjusted accordingly to reflect the increased SRV safety setpoints and the higher system operating pressures.

The RCIC turbine is verified to be capable of operating at the increased steam supply pressures and temperatures with this program. The RCIC pump was originally designed with sufficient head to meet the new injection pressure requirements while still maintaining an adequate system operating margin.

The impact of this SRV setpoint tolerance relaxation on the remainder of the system components was determined to be negligible because of the very small increase in operating pressure and/or temperature.

6.3 STANDBY LIQUID CONTROL SYSTEM PERFORMANCE EVALUATION

The Standby Liquid Control System is a redundant reactivity control system capable of shutting down the reactor from rated power condition to cold shutdown in the postulated condition that all or some of the control rods cannot be inserted. It is an automatically operated system that will pump a sodium pentaborate solution into the vessel in order to provide neutron absorption and achieve a subcritical reactor condition.

6.3.1 System Functions and Requirements

The design criterion for this system is to provide a prescribed boron concentration in solution into the reactor (660 ppm). Technical Specification limits are placed on this system to assure adequate reactor shutdown margin. These limits are expressed in terms of acceptable solution volume and concentration operating regions. The operation of a single SLCS pump at a minimum flow rate of 41.2 gpm, meets the boron injection rate requirements for continued decreasing reactivity as the core cools down.

NRC ATWS Rule 10CFR50.62, paragraph (c)(4), specified that "each boiling water reactor must have a standby liquid control system with a minimum flow capacity and boron content equivalent in control capacity to 86 gallons per minute of 13-weight percent sodium pentaborate solution." The 86 gpm / 13 weight percent values were for plants with a 251-inch diameter vessel. For HCGS, the equivalency requirement was met with two pumps operating and a naturally enriched boron at a standard solution concentration of 13.6 weight percent.

The maximum reactor pressure at which the SLCS pumps could be called upon to inject sodium pentaborate into the reactor is determined by the upper setpoint pressure for the lowest group of SRVs. The maximum pressure at the discharge of the SLCS pumps is the SRV setpoint pressure plus the head of water in the reactor and the pump discharge system flow and head losses. The maximum system head loss occurs for the case where both pumps are initiated automatically for NRC ATWS Rule compliance.

6.3.2 Inputs and Assumptions

The following values constitute the present design of the SLCS :

Pump Nominal Flow Rate	= 43.0 gpm (each)
Two Pump Injection Rate	= 82 gpm
Maximum Pressure at Core Spray Line	= 1134 psig
Injection Rate (Boron)	= 6 to 25 ppm/min
Reactor Boron Concentration	= 660 ppm

Pump relief valve maximum setpoint = 1400 psig

6.3.3 System Evaluation

The most significant impact on the performance of the SLCS is the higher reactor operating pressure. The SLCS System was originally designed to provide injection into the reactor pressure vessel from zero pressure up to at least 1% above the lowest nominal relief setpoint of the lowest group of SRVs, which currently corresponds to a reactor pressure of 1120 psig. With the setpoint tolerance relaxation program, the SRV safety setpoint tolerances are being increased from ±1 % to ± 3%. This change increases the maximum reactor pressure for SLCS system injection by 21 psi, from 1120 psig to 1141 psig.

The maximum pressure at the SLCS pumps is a function of the SRV setpoint pressure plus the pump discharge system flow and head losses. The discharge system total flow losses were estimated at 56 psig with one pump operating, and 90 psig with two pumps operating (each having a design flow rate of 43 gpm). The maximum pressure in the core spray line where the sodium pentaborate is injected into the reactor is specified as 1134 psig at a corresponding reactor pressure of 1120 psig. With the SRV setpoint tolerance change, this pressure increases 21 psi to 1155 psig. Thus, the maximum pump discharge pressure (with two pumps operating for compliance with the NRC ATWS Rule) is simply the pressure in the core spray line (1155 psig), plus the system flow and head loss (90 + 10 psig), for a pump discharge pressure of 1255 psig. This results in a SLCS relief valve pressure margin of 103 psi (below nominal setpoint), compared to a valve pressure margin requirement of 75 psi for the system to reliably provide full pump discharge flow to the reactor. At pressure margins less than 75 psi, there is a high probability of relief valve leakage due to the pressure pulses in the pump discharge lines generated by the positive displacement pumps. Leakage from each relief valve is returned to its pump inlet suction line. The SLCS pump relief valves are simple spring loaded poppet valves, which open when the force of the fluid on the high pressure side of the valve exceeds the force of the spring keeping the valve closed. A check valve located in the discharge line from each pump (downstream of the relief valve connection), prevents cross flow from the other operating pump loop from discharging through an opened relief valve. Consequently, the opening of a single relief valve will not effect the operation of the remaining pump loop.

A comparison of the SLCS performance characteristics for the current system design basis and after including the increased SRV setpoint tolerance is shown in Table 6-3.

The ability of the SLCS pump to inject its design flow rate into the reactor vessel is not directly affected by this program. The SLCS pumps are positive displacement type pumps which have a nearly constant flow characteristic with increasing discharge pressure. The design pressure of the pumps and the discharge side of the system is 1400 psig which is well above the calculated maximum system operating pressure. The electric motors used to drive the pumps are rated at 40 hp and have sufficient horsepower margin to meet the new pump power requirements.

6.3.4 Conclusion

An evaluation of the SLCS performance at the increased SRV tolerance setpoint pressure limit found that the system has the capability to deliver the required flowrate of neutron absorber solution to the reactor pressure vessel. The impact of this proposed change on the remainder of the system components was determined to be negligible because the system operating pressures remain well below the system design pressures. No modifications or setpoint changes are required for the SLCS as a result of this change.

Table 6-1
HPCI SYSTEM PERFORMANCE COMPARISON

SRV Setpoint Tolerance	± 1%	± 3%
Maximum Reactor Dome Pressure for HPCI injection, psig	1120	1141
Pump Discharge Pressure		
Original Design, psig	1272	
Calculated, psig	1218	1239
System Flow Rate, gpm	5600	5600
<u>Pump Characteristics</u>		
Total Dynamic Head, ft	2950	2950
Pump Flow Rate, gpm	5600	5600
Shaft Speed, RPM	4000	4000
Brake Horsepower, HP	4925	4925
<u>Turbine Characteristics</u>		
Turbine Steam Supply Pressure, psig	1105	1126
Steam Flow Rate, lbm/hr	235000	< 235000
Design Rated Speed, RPM	4000	4000
Nominal Overspeed Trip Speed, RPM	5000	5000
Overspeed Trip Setpoint Margin percent speed (1)	125	125

Notes:

(1) Based on nominal rated trip speed

Table 6-2
RCIC SYSTEM PERFORMANCE COMPARISON

SRV Setpoint Tolerance	$\pm$ 1%	$\pm$ 3%
Maximum Reactor Dome Pressure for RCIC injection, psig	1120	1141
System Flow Rate, gpm	600	600
<u>Pump Characteristics</u>		
Total Dynamic Head, ft	2800	2850
Pump Flow Rate, gpm	625	625
Required Shaft Speed, RPM	4450	4490
Brake Horsepower, HP	640	656
<u>Turbine Characteristics</u>		
Turbine Steam Supply Pressure, psig	1105	1126
Steam Flow Rate, lbm/hr	33000	33700
Design Rated Speed, RPM	4500	4500
Nominal Overspeed Trip Speed, RPM	5625	5625
Overspeed Trip Setpoint Margin percent speed (1)	125	125

Notes:

(1) Based on nominal rated trip speed.

Table 6-3
STANDBY LIQUID CONTROL SYSTEM
PERFORMANCE COMPARISON
TWO-PUMP PERFORMANCE EVALUATION

SRV Setpoint Tolerance	± 1%	± 3%
Maximum Reactor Dome Pressure for SLCS injection, psig	1120	1141
Maximum Core Spray Line Pressure, psig	1134	1155
Injection Flow Rate, gpm	82	82
System Parameters		
System Flow & Head Losses, psig	100	100
Pump Discharge Pressure, psig	1234	1255
Required Motor Power, hp (40 hp rating)	34.4	35.0
SLCS Relief Valve (± 3% Tolerance)		
Maximum Setting, psig	1400	1400
Nominal Setting, psig	1358	1358
SLCS Relief Valve Margin, psig (From Nominal)	124	103
Required Relief Valve Margin For Full Flow To Reactor, psig	75	75

7.0 CONTAINMENT EVALUATION

An increase in the tolerance of the SRV opening setpoints to ±3% was assessed for potential impact on the containment pressure and temperature response and on the containment hydrodynamic loads. Additionally, an upper pressure limit for each valve was determined.

7.1. CONTAINMENT PRESSURE AND TEMPERATURE

The effect on the peak containment pressure and temperature response and on the peak suppression pool temperature for the respective limiting events were considered. The most limiting event in terms of peak containment pressure response and peak suppression pool temperature is the design basis accident (DBA) LOCA, a double ended guillotine break of the recirculation line. Relaxation of the SRV setpoint tolerance has no effect on this event since the vessel depressurizes without any SRV actuations. Therefore, there is no impact on the DBA-LOCA containment pressure and temperature and on the peak DBA-LOCA suppression pool temperature.

Small steam line breaks can result in high drywell temperature conditions which can last for a relatively long period of time since the vessel remains at high pressure for a longer period than the DBA. For small steam line breaks with RPV isolation and subsequent SRV actuations, the peak drywell temperature occurs relatively late in the event following many SRV actuations. After the first SRV opening at the drifted setpoints, subsequent openings will be at lower pressures, either around the nominal setpoint or at the adjusted lower setpoint dictated by LLS logic on the two preselected LLS SRVs (valves H and P). The peak drywell temperature therefore will not be affected as it occurs well after the SRV opening setpoints have been restored to their nominal values (or LLS values) and the valves have been cycling in their normal pressure range. Therefore, an increase in the initial SRV opening setpoint pressure due to SRV drift will have a negligible effect on the peak drywell temperature for small steamline breaks.

7.2. SAFETY/RELIEF VALVE DYNAMIC LOADS

This study evaluates the impact on the SRV piping design and containment structural loads of setting the SRV setpoint tolerances to +3% above the current valve setpoints at HCGS. A single upper limit is not feasible as there is very little available margin in select areas of the containment, and thus it was decided that the upper limit be determined on a valve specific basis.

Upon SRV actuation, pressure and thrust loads are exerted on the SRV discharge piping and T-quencher. Additionally, the expulsion of water and air into the suppression pool through the T-quencher results in pressure loads on the submerged portion of the torus shell, and drag loads on submerged structures. These SRV discharge loads have the potential to be affected due to an increase in SRV flow rates at the higher opening setpoints. These loads are described in Section 5 of the Mark I Containment Load Definition Report (Ref. 8), and are summarized as follows:

(1) Thrust Loads on SRV discharge piping and T-quencher.
(2) Torus Shell pressures.
(3) Water Jet loads and air bubble induced drag loads on submerged structures.

The calculated stress on a particular structure is determined by [ ]. Reference 8 prescribes the loading combinations to be considered. The HCGS Plant Unique Analysis Report (PUAR, Ref. 9) determines the limiting load combination, the actual load, and the allowable load for a given component.

This section considers [ ] to investigate the acceptability of the proposed increase to the SRV tolerance setpoint.

7.2.1 EVALUATION APPROACH

The Reference 9 analyses for the containment loads for Hope Creek are based on the valves' safety function opening at the nominal setpoint. This section analyzes the impact of increasing the SRV (safety mode) opening setpoint tolerance from nominal to an upper limit of +3% or more, determined on a individual valve basis. Such an increase in the valves' opening setpoint will result in an increase in the internal containment loads. [ ].

7.2.2 SRV FLOW RATE CALCULATION

The SRV flow rates used for the current evaluation are calculated using the same method as used for the Reference 9 analyses. [ ]

Based on this method an increase in the SRV setpoint to 1164 psig (largest SRV setpoint + 3% tolerance) would result in a 3% increase in flow rate. Accordingly, calculated SRV discharge loads on containment detailed in the PUAR and Snubber Reduction Project stress reports (Refs 12-15) were scaled by 1.03 in order to quantify the effects of increasing the setpoint on safety margins.

7.2.3 SRV LOADS EVALUATION

There are two basic components of the SRV loads during SRV actuation:

(1) The internal SRV discharge line loads which include the loads on the SRV discharge lines, the T-quencher and their supporting structures.

(2) The loads on the torus submerged boundaries and submerged structures.

The internal line loads result from internal pressures and hydraulic thrust loads in the SRV discharge line and in the T-quencher. The loads on the torus shell and on submerged structures result from the formation and subsequent oscillation of the air bubbles which form adjacent to the T-quencher. The oscillating air bubbles produce dynamic positive and negative pressures relative to the ambient pressure within the bubble which are attenuated to the torus shell. The oscillating bubbles also produce flow fields in the suppression pool which induce standard and acceleration drag forces on the submerged structures. Consideration of a third issue was also requested by HCGS, which is the effect of the increased SRV discharge on supporting snubbers with respect to the HCGS snubber reduction project.[1]

[1] It has been advised that HCGS is considering replacing all current snubbers with hydraulic Lisega snubbers; the evaluation in this report only covers the Pacific Scientific and E-System snubbers currently in use.

7.2.3.1 Internal SRV Loads

The internal SRV loads include the pressure and thrust loads on the SRV discharge line, T-quenchers, and their supports. For the T-quencher and the portion of the SRV discharge lines located in the wetwell, the thrust loads resulting from the expulsion of the water column initially in the discharge lines and the T-quencher are the dominant. As previously stated, an increase in the SRV flow rate of 3% would result in a 3% increase in SRV loads.

7.2.3.1.1 Loads on the Quencher and Quencher Support

The SRV thrust loads used to calculate the water clearing thrust loads on the quencher and quencher support were calculated using [ ] Therefore, the 3% increase in the SRV flow will not adversely impact the loads on the quencher and quencher supports.

7.2.3.1.2 Loads on SRV Piping in the Drywell

[ ] however, it was shown that a 3% increase on each nominal setpoint will not cause exceedance of the allowable stresses. The upper limit for each valve based on the SRVDL allowable stresses is contained in Table 7-1.

7.2.3.2 SRV Loads in the Torus Pool

SRV loads in the torus pool include the loads on the torus shell, the loads on submerged structures in the torus pool, and the torus shell loads which are transmitted to the torus attached piping.

7.2.3.2.1 Torus Shell, Torus Support Loads and Torus Attached Piping

Containment structures affected by torus shell pressures include the torus shell, torus support structures and torus attached piping. Reference 10 documents the redefinition of multiple valve actuation (MVA) torus bubble pressure loads in order to justify the acceptability of an increase in SRV setpoint drift on the torus and torus attached structures. This evaluation uncovered a conservatism of at least 21% in torus shell pressures, torus shell stresses, and torus attached piping, which bounds the loads on these structures up to a drift of +21%.

7.2.3.2.2 Submerged Structure Loads

As the air and steam/air mixture are discharged into the suppression pool via the SRV, these air bubble formations create acceleration and drag loads which are exerted on the submerged structures. The containment structures which could be affected by these water jet or air bubble drag loads include such submerged structures as torus vent system penetrations, ring girders, vent header supports, and downcomers. As the current design basis for these components is maintained by VECTRA, the impact of the increase in SRV setpoint tolerance on these components was evaluated by VECTRA (Ref 11). The evaluation (Ref. 11) determined a conservatism of at least 20% in the SRV loads defined for the vent system, vent system penetrations and vent system support structures. This bounds the loads for SRV setpoint drift of up to 20%.

7.2.3.3 Snubber Reduction/Addition Project Effects

Implementation of the snubber reduction program involved deletion of many snubbers, and replacement of others with struts. All remaining snubbers and the added struts are sufficient for the increased loads (Refs 12-15). Some strut and snubber data was unavailable for MS lines A and B for these analyses; however based on the available information and the similarity between lines, large margins [ ] are expected on these lines. Information on allowable stresses was not required as part of the data input for some of the analyses and thus was not always contained in the analysis reports. Lacking this information, the similarity between lines A and D and also between B and C was assumed to be typical, and the large margins [ ] in C and D were assumed representative of A and B where the information was missing. It is also assumed that the welds are sufficient for the allowable loads, which far exceed the calculated loading even with the 3% increase. The snubber reduction project had the effect of severely cutting the margin in the SRVDLs, and they had to be studied on an individual valve basis. The ±3% setpoint relaxation was found to be acceptable upon conclusion of this study.

7.3. CONCLUSIONS

Increasing the opening setpoint tolerances of the SRVs from ±1% to ±3% and setting the upper limit to the analytical limits found in Table 7-1 (not to exceed 1250 psig) will not result in the exceedance of allowable stresses in the containment structures.

Table 7-1
INDIVIDUAL SRV ANALYTICAL LIMITS

Main Steam Line	SRV Line	Highest Stressed Node	Nominal Setpoint on which MAPI is based (psig)	Maximum Allowable Percent Increase Above SRV Nominal Setpoints (MAPI)
A	A	382	1130	3.0
	J	152F	1120	8.9
	R	282N	1120	10.9
B	B	340	1130	39.4(1)
	F	431	1108	5.5
	K	220F	1108	22.4(1)
	P	140	1120	27.4(1)
C	C	348F	1130	21.8(1)
	E	110F	1130	6.9
	G	406	1120	8.7
	L	218N	1120	16.3
D	D	236F	1130	17.6
	H	336	1108	37.7(1)
	M	134N	1108	27.0(1)

Note for Table: (1) This is the maximum allowable increase for the SRV discharge lines. Other containment issues however dictate that the maximum drift must remain below 1250 psig.

8.0 ATWS MITIGATION ANALYSIS

The potential impact of Safety Relief Valve tolerance setpoint relaxation to ±3% with one SRV out-of-service on the HCGS Anticipated Transient Without Scram performance is examined to verify compliance with the ASME vessel overpressure protection criterion of 1500 psig (Emergency Condition).

8.1 ATWS ANALYSIS ASSUMPTIONS

The limiting event for this ATWS condition is the Main Steamline Isolation Valve closure transient. For such an event, it is conservatively assumed that the reactor scram does not take place on any reactor protection system signals. Thus, the eventual shutdown of the plant for this postulated event is by the use of the Standby Liquid Control System. The initial reduction in power occurs by the use of the ATWS high dome pressure recirculation pump trip (RPT) signal. After the ATWS RPT function is actuated and following the actuation of the SRVs, the event is terminated.

Consistent with MSIV closure with the flux scram analysis in Section 3.0, the ATWS analysis assumes the same single upper limit setpoint of 1250 psig for all SRVs to bound potential SRV drift beyond the ±3% range of the nominal trip setpoint. The following assumptions were used to study the effect of SRV setpoint relaxation and SRV OOS on this ATWS event:

(1) The reactor is operating at 100% power/87% core flow. This is the limiting state point for ATWS analysis consideration because at this maximum power/minimum core flow condition the effectiveness of the ATWS RPT is less pronounced than at higher core flows (rated or increased core flow conditions).

(2) 4-second nominal closure time of the MSIV.

(3) [ ].

(4) A single upper limit setpoint of 1250 psig for the available 13 SRVs with one SRV OOS for design basis considerations.

(5) ATWS RPT high pressure technical specification upper limit setpoint of 1086 psig.

(6) [ ]

This ATWS event is analyzed with the REDY transient model (Ref. 16) which consists of [ ]. [ ]. The analytical inputs and methodology are consistent with those used in the [ ]

8.2 ATWS ANALYSIS RESULTS

For this MSIV closure with no scram event analyzed with the single upper limit setpoint of 1250 psig for 13 SRVs available (out of the total number of 14 SRVs), the peak reactor vessel bottom pressure was calculated to be 1425 psig, which is less than the ASME service level C (Emergency) value of 1500 psig. The transient peak values are summarized in Table 8-1 and key parameter time histories are presented in Figure 8-1.

Therefore, it is concluded that the use of the single upper limit setpoint of 1250 psig, which bounds potential SRV drift beyond the ±3% range of the current nominal trip setpoint, for the current technical specification requirement configuration of 13 out of the total number of 14 SRVs (the lowest setpoint SRV out-of-service), does not adversely impact the vessel overpressurization criteria for the limiting ATWS event.

Table 8-1
ATWS MSIV CLOSURE
TRANSIENT RESPONSES

Power/Flow (% of Rated)	SRV Configuration	Peak Neutron Flux (% NBR)	Peak Average Heat Flux (% NBR)	Peak Steamline Pressure psig	Peak Vessel Bottom Pressure psig
100/87	1250 psig 13 SRVs	482	148	1383	1425

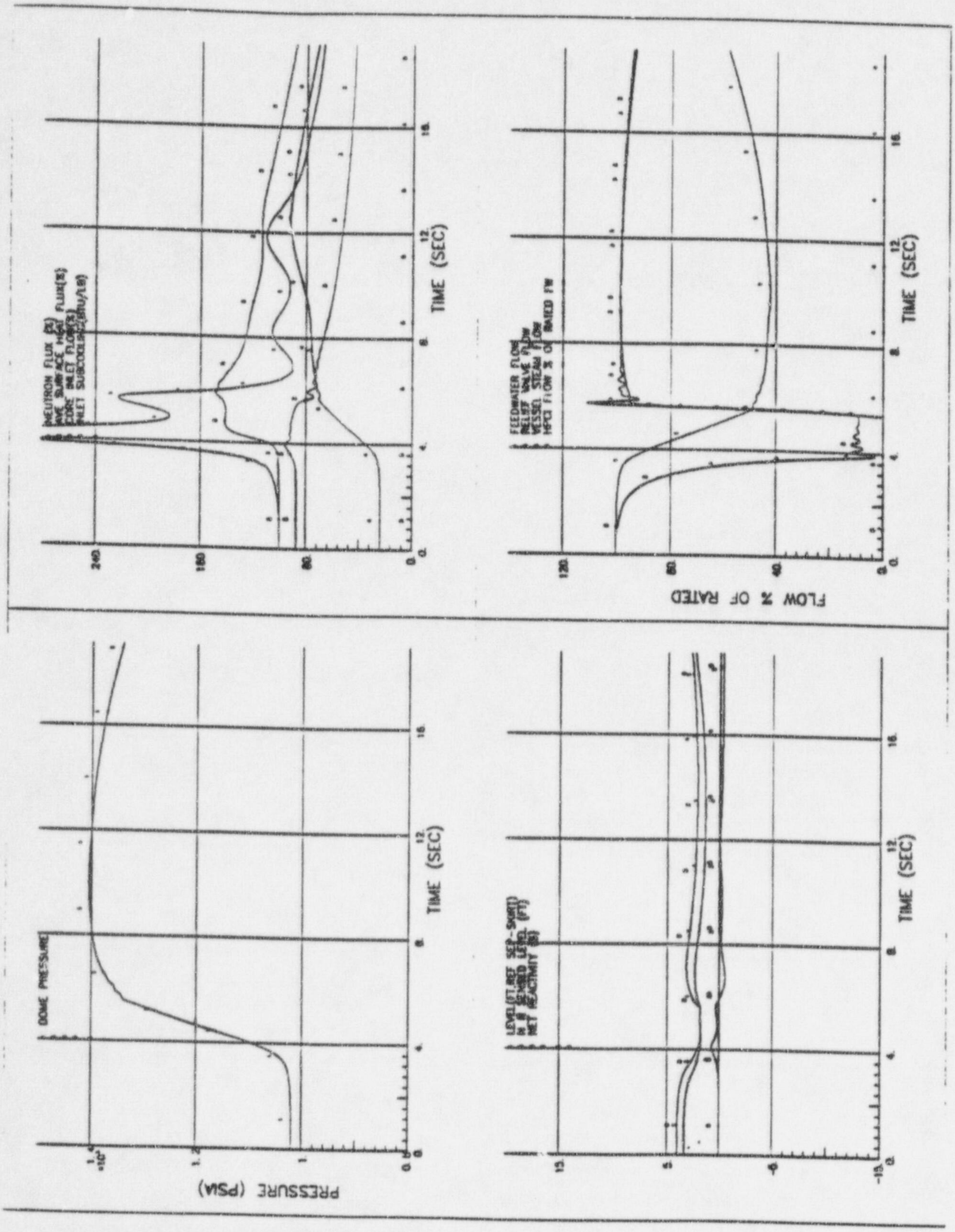

Figure 8-1 MSIV Closure No Scram Event, 100% Power/87% Core Flow, Single Upper Limit of 1250 psig, 13 SRVs in Service

9.0 TECHNICAL SPECIFICATIONS

The Hope Creek plant-specific Technical Specifications were reviewed to determine the impact of changes proposed by this study. Technical Specifications Limiting Conditions for Operation, Surveillance Requirements, and Bases Sections 3/4.4.2 were affected. Mark-ups of these sections, which reflect the results of this study, are provided in the Attachment.

As indicated in the mark-ups, limiting conditions for operation of the SRVs were relaxed from ±1% to ±3%. Allowances were made to require surveillances to verify setpoints to be within ±3% of the values called out in the Technical Specifications but that prior to placing SRVs in service following setpoint verification testing, the setpoints must be returned to within ±1% of the Technical Specification-specified values. Based on the pressure setpoint Upper Limit which was established, allowances were provided in the Technical Specifications bases to allow operation to the next scheduled outage if setpoints drift to values greater than the tolerances specified but remaining below the Upper Limit.

10.0 CONCLUSIONS

Based on the evaluations and analyses performed and described in the foregoing sections of this report, it has been determined that all the proposed performance objectives listed in Table 1-1 are satisfactory for Hope Creek. In particular, the study which forms the basis for this report supports relaxation of the tolerances on the opening setpoints of the SRVs from ±1% to ±3%. In addition, an Upper Limit on each SRV was determined, and they are tabulated in Table 7-1. Marked-up pages of pertinent sections of the Technical Specifications which reflect the results of this study are attached.

Analyses indicated that an Upper Limit of 1250 psig was satisfactory for all cases, except for the containment loads evaluation. Plant locations at which margins were found not to support an Upper Limit of 1250 psig include the SRVDLs as specified in Table 7-1. Modifications by Hope Creek to enhance loading capabilities at the indicated locations could result in increasing the restricted Upper Limits (in the containment) to higher pressures.

All calculations and evaluations were performed with one SRV out-of-service. The results for ECCS/LOCA performance, high pressure system performance, containment response, and ATWS mitigation are cycle independent. The vessel overpressurization analysis and fuel thermal limits evaluation are cycle dependent. These were performed for Cycle 7, and it is suggested that vessel overpressure and thermal margin determinations be re-performed for succeeding cycles as a part of reload licensing evaluations.

11. REFERENCES

1. Hope Creek Generating Station, Transient Protection Parameters Verification for Reload Licensing Analysis, Reload 6 Cycle 7 (OPL-3 Form).
2. ANSI/ASME 1983 Edition, Winter 1983 Addenda.
3. 24A5173, Supplemental Reload Licensing Report for Hope Creek Generating Station Unit 1 Reload 6 Cycle 7, Rev.0, July, 1995.
4. [ ]
5. NEDE-24011-P-A-11, General Electric Standard Application for Reactor Fuel, GESTAR II, and NEDE-24011-P-A-11-US, GESTAR II US Supplement, November 1995.
6. NEDC-31753P, BWROG In-Service Pressure Relief Technical Specification Revision Licensing Topical Report, February, 1990.
7. Hope Creek Generating Station Updated Final Safety Analysis Report.
8. NEDO-21888, Mark I Containment Program Load Definition Report, Rev. 2, including Errata and Addenda No. 1, General Electric Company, April, 1982.
9. BPC-01-0300, Hope Creek Generating Station Plant Unique Analysis Report (PUAR), Vols. 1-6, NUTECH Report, January, 1984.
10. Letter OLA-96-001 from Olof Andersson (VECTRA) to Joe Ondish (PSE&G) dated 1/4/96. Subject: Acceptability of an Increase in SRV Setpoint Drift on the Torus and Torus Attached Structures.
11. "Acceptability of an Increase in SRV Setpoint Drift on the Suppression Pool Vent System and Submerged Structures", VECTRA Calculation Package No. 0014.00106.F02.02, 3/20/1996.
12. 23A6126, Main Steam System Line A Piping and Equipment Loads, Rev. 1, February, 1989.
13. 23A6127, Main Steam System Line B Piping and Equipment Loads, Rev. 1, February, 1989.
14. 23A6128, Main Steam System Line C Piping and Equipment Loads, Rev. 1, February, 1989.
15. 23A6129, Main Steam System Line D Piping and Equipment Loads, Rev. 1, February, 1989.
16. NEDO-10802, Analytical Method of Plant Transient Evaluation for the General Electric Boiling Water Reactor, February, 1973, as amended.
17. [ ]
18. [ ]

ATTACHMENT

Marked-up Pages of Affected Technical Specifications Sections

3/4.4.2 SAFETY/RELIEF VALVES

SAFETY/RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.2.1 The safety valve function of at least 13 of the following reactor coolant system safety/relief valves shall be OPERABLE*# with the specified code safety valve function lift settings:**

4 safety-relief valves @ 1108 psig ~~±1%~~ ± 3%
5 safety-relief valves @ 1120 psig ~~±1%~~ ± 3%
5 safety-relief valves @ 1130 psig ~~±1%~~ ± 3%

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2 and 3.

INSERT A

ACTION:

otherwise

b. ~~a.~~ With the safety valve function of two or more of the above listed fourteen safety/relief valves inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

c. ~~b.~~ With one or more safety/relief valves stuck open, provided that suppression pool average water temperature is less than 110°F, close the stuck open safety relief valve(s); if unable to close the stuck open valve(s) within 2 minutes or if suppression pool average water temperature is 110°F or greater, place the reactor mode switch in the Shutdown position.

d. ~~c.~~ With one or more of the above required safety/relief valve acoustic monitors inoperable, restore the inoperable monitors to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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*SRVs which perform as ADS function must also satisfy the OPERABILITY requirements of Specification 3.5.1, ECCS-Operating.
**The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures.
#SRVs which perform a low-low set function must also satisfy the OPERABILITY requirements of Specification 3.4.2.2, Safety/Relief Valves Low-Low Set Function.

SURVEILLANCE REQUIREMENTS

4.4.2.1 The acoustic monitor for each safety/relief valve shall be demonstrated OPERABLE with the setpoint verified to be ≤ 30% of full open noise level** by performance of a:

a. CHANNEL FUNCTIONAL TEST at least once per 31 days, and a

b. CHANNEL CALIBRATION at least once per 18 months*.

4.4.2.2 At least 1/2 of the safety relief valve pilot stage assemblies shall be removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations at least once per 18 months, and they shall be rotated such that all 14 safety relief valve pilot stage assemblies are removed, set pressure tested and reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations at least once per 40 months. ALL SAFETY RELIEF VALVES WILL BE RECERTIFICATION TESTED TO MEET A ±1% TOLERANCE PRIOR TO RETURNING THE VALVES TO SERVICE.

4.4.2.3 The safety relief valve main (mechanical) stage assemblies shall be set pressure tested, reinstalled or replaced with spares that have been previously set pressure tested and stored in accordance with manufacturer's recommendations at least once every 5 years.

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*The provisions of Specification 4.0.4 are not applicable provided the Surveillance is performed within 12 hours after reactor steam pressure is adequate to perform the test.

**Initial setting shall be in accordance with the manufacturer's recommendations. Adjustment to the valve full open noise level shall be accomplished after the initial noise traces have been analyzed.

Stability tests at operating BWRs were reviewed to determine a generic region of the power/flow map in which surveillance of neutron flux noise levels should be performed. A conservation decay ratio of 0.6 was chosen as the bases for determining the generic region for surveillance to account for the plant to plant variability of decay ratio with core and fuel designs. This generic region has been determined to correspond to a core flow of less than or equal to 4[illegible]% of rated core flow and a THERMAL POWER greater than that specified in Figure 3.4.1.1-1.

Plant specific calculations can be performed to determine an applicable region for monitoring neutron flux noise levels. In this case the degree of conservatism can be reduced since plant to plant variability would be eliminated. In this case, adequate margin will be assured by monitoring the region which has a decay ratio greater than or equal to 0.8.

Neutron flux noise limits are also established to ensure early detection of limit cycle neutron flux oscillations. BWR cores typically operate with neutron flux noise caused by random boiling and flow noise. Typical neutron flux noise levels of 1-12% of rated power (peak-to-peak) have been reported for the range of low to high recirculation loop flow during both single and dual recirculation loop operation. Neutron flux noise levels which significantly bound these values are considered in the thermal/mechanical design of GE BWR fuel and are found to be of negligible consequence. In addition, stability tests at operating BWRs have demonstrated that when stability related neutron flux limit cycle oscillations occur they result in peak-to-peak neutron flux limit cycles of 5-10 times the typical values. Therefore, actions taken to reduce neutron flux noise levels exceeding three (3) times the typical value are sufficient to ensure early detection of limit cycle neutron flux oscillations.

Typically, neutron flux noise levels show a gradual increase in absolute magnitude as core flow is increased (constant control rod pattern) with two reactor recirculation loops in operation. Therefore, the baseline neutron flux noise level obtained at a specific core flow can be applied over a range of core flows. To maintain a reasonable variation between the low flow and high flow end of the flow range, the range over which a specific baseline is applied should not exceed 20% of rated core flow with two recirculation loops in operation. Data from tests and operating plants indicate that a range of 20% of rated core flow will result in approximately a 50% increase in neutron flux noise level during operation with two recirculation loops. Baseline data should be taken near the maximum rod line at which the majority of operation will occur. However, baseline date taken at lower rod lines (i.e., lower power) will result in a conservative value since the neutron flux noise level is proportional to the power level at a given core flow.

3/4.4.2 SAFETY/RELIEF VALVES

The safety valve function of the safety/relief valves operates to prevent the reactor coolant system from being pressurized above the Safety Limit of 1375 psig in accordance with the ASME Code. A total of 13 OPERABLE safety/relief valves is required to limit reactor pressure to within ASME III allowable values for the worst case transient.

INSERT B

Demonstration of the safety relief valve lift settings occurs only during shutdown. The safety relief valve pilot stage assemblies are set pressure tested in accordance with the recommendations of General Electric SIL No. 196, Supplement 14 (April 23, 1984), "Target Rock 2-Stage SRV Set-Point Drift." Set pressure tests of the safety relief valve main (mechanical) stage are conducted at least once every 5 years.

The low-low set system ensures that safety/relief valve discharges are minimized for a second opening of these valves, following any overpressure transient. This is achieved by automatically lowering the closing setpoint of two valves and lowering the opening setpoint of two valves following the initial opening. In this way, the frequency and magnitude of the containment blowdown duty cycle is substantially reduced. Sufficient redundancy is provided for the low-low set system such that failure of any one valve to open or close at its reduced setpoint does not violate the design basis.

TECHNICAL SPECIFICATION INSERTS

INSERT A

a. With the peak lift pressure of the safety function of two or more of the above required safety/relief valves above the +3% tolerance, operation may continue provided the peak lift pressure of each valve is less than or equal to the Upper Limit. The provisions of Specification 3.0.4 are not applicable. Otherwise, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

INSERT B

Analyses have been performed to demonstrate that the ASME Section III allowable values are not exceeded for the worst case transients assuming the safety function of the safety relief valves have lift pressures equal to the Upper Limit. (References: 1. BWROG In-Service Pressure Relief Technical Specification Revision Licensing Topical Report, NEDC-31753P, October 1989, and 2. the corresponding plant-specific report.) Consequently, with the lift pressures outside the ±3% tolerance and less than or equal to the Upper Limit, operation may continue provided (1) a report is submitted to the NRC within 90 days and (2) the affected safety/relief valves are removed and the setpoints re-established to be within ±1% of the nameplate set pressure and reinstalled or replaced with spares at the next refueling outage.