CONSIDERATIONS ASSOCIATED WITH CHANGING ELECTROMATIC RELIEF VALVE (EMRV) SETPOINTS

Report 101
REV. 0

Project No:/Technical Specification Change Request No. 216/TDR 1123

Authors: Raymond S. Markowski
Raymond S. Markowski

Date: June 1994

Approvals:

SECTION MANAGER — 6/1/94 DATE

G.R. Bond
DEPARTMENT DIRECTOR — 6-2-94 DATE

NOT APPLICABLE
DIRECTOR, TECHNICAL FUNCTIONS (SIGNIFICANT IMPACT REVIEW) — DATE

ABSTRACT

This Topical Report provides the evaluations, analyses, considerations, margins, etc. associated with changes to the Electromatic Relief Valve (EMRV) high pressure and automatic depressurization opening and/or closing setpoints. It was developed initially to provide the detailed basis and approach for developing the significant hazards evaluation for Technical Specification Change Request (TSCR) No. 216.

Another purpose of this Topical Report is to provide a more complete, current and precise delineation of the design and licensing basis of EMRV setpoints.

TABLE OF CONTENTS

1.0 GENERAL

The Electromatic Relief Valves (EMRV) provide high pressure prevention and automatic depressurization functions. The EMRVs are "relief valves" as defined by ANSI B95.1-1972. The high pressure prevention function minimizes the peak pressures experienced during pressurization transients. The automatic depressurization function (ADS) provides the Emergency Core Cooling function (ECCS) of depressurizing the reactor vessel quick enough, during small break Loss Of Coolant Accidents (LOCA), to ensure that the Core Spray System can be effective in preventing core damage.

Five EMRVs are currently installed upstream of the inboard Main Steam Isolation Valves. The valves are grouped into two banks of two (North Header) and three (South Header) respectively. The EMRV specific safety significant performance characteristics consist of the:

(1) capacity at actuation setpoint pressure;

(2) opening time;

(3) probability of inadvertent actuation; and,

(4) probability of sticking open.

Of additional safety significance is the number of EMRVs that actuate, the number of subsequent actuations that occur; and, the time between subsequent actuations.

Currently, utilizing staggered high pressure actuation open and close setpoints and automatic depressurization time delay relaying, the EMRVs are set such that sequential opening and closing of the EMRVs within a given EMRV discharge header will occur for both high pressure and ADS actuation. As explained further in this Topical Report, this sequential operating strategy is no longer needed for nuclear safety reasons. Refer to Section 4.0 of this Topical Report. However, this sequential operating strategy will provide for the retention of an additional level of structural robustness of the torus, torus attached piping, torus internal structures and the EMRV inlet connection and discharge header for life extension and maintenance rule purposes.

2.0 HISTORICAL PERSPECTIVE - EMRV SETPOINTS

Oyster Creek began power operation with four Electromatic Relief Valves (EMRV) which were required by the Technical Specifications to be set at less than or equal to 1125 psig. The initial licensed power level was 1600 MWt with a nominal operating pressure of 1015 psia.

In December 1970, Amendment 65 to the then Facility Design and Safety Analysis Report (FDSAR) was submitted to support the increase in licensed power to 1930 MWt. To be licensed for that power level, it was determined that an additional EMRV was required. Also, the nominal plant operating pressure was increased to 1035 psia. The capacities and setpoints of the EMRVs, at this time, were established based on limiting the pressure peak reached during a Turbine Trip WITHOUT Bypass (TTWOBP) transient to below the setpoint of the first safety valve. At this time, the TTWOBP was called the "Relief Valve Sizing Transient." Also, the EMRV setpoint was to be set high enough so that the EMRVs would not actuate during a Turbine Trip WITH Bypass transient.

Amendment 69 to the FDSAR was submitted in May 1972. That amendment, which was associated with the Cycle 2 Reload, addressed a notification from General Electric of a significant change in the shape of the End of Cycle (EOC) scram reactivity curve. The effect of what turned out to be a poorer EOC shape was more severe pressurization transients. The options proposed at the time to REGAIN required margins were (a) addition of more EMRVs, (b) changing EMRV and/or safety valve setpoints, (c) changing scram times, (d) taking credit, if possible, for faster EMRV opening time and/or (e) reducing the nominal plant operating pressure. As a result of reanalysis of pressurization transients, the Technical Specification specified EMRV high pressure actuation setpoint was reduced to less than or equal to 1070 psig.

In November 1976, measurements of the structural response of the torus to EMRV actuation at 1035 psia indicated that certain EMRV opening sequences could produce unacceptably high stresses on the torus. As a short term compensatory action, the EMRV high pressure actuation setpoints and automatic depressurization time delaying were staggered/modified to prevent more than one EMRV in each header from opening until "steam vent clearing" was completed (Refer to Steam Clearing Phenomenon references 10 and 11). Additional time delay relays were added to the Automatic Depressurization System to achieve this staggered lift sequence in the ADS mode.

Also, at that time, the high pressure actuation closure setpoint of one EMRV in each header was set to contribute to providing a three minute time interval before a subsequent EMRV actuation(s) would occur. This time interval was necessary at that time because the EMRV discharge header vacuum breaker capacity was such that long water slugs were created and expelled during second/subsequent EMRV actuations. This three minute interval is no longer required to be maintained. Refer to section 4.0, Steam Vent Clearing Phenomenon, of this report for more details. Note that the Technical Specification Setpoint of less than or equal to 1070 psig was not required to be and was not changed at that time.

Technical Specification Change Request (TSCR) No. 98, which resulted in Amendment No. 62, requested the increase of the Technical Specification specified high pressure actuation setpoint of three EMRVs from ≤1070 to ≤1090 psig. At the time, the Technical Specification specified setpoint was all five (5) EMRVs ≤1070 psig. The purpose of the change was to address NUREG-0737, Item II.K.3.16 by reestablishing a 50 psi margin to normal plant pressure concurrent with maintaining a 20 psi difference between EMRVs within a given header. This 20 psi difference was based on the use of a staggered setpoint approached to mitigate the effects of the "steam vent clearing phenomenon."

Of significance is that Technical Specification Change Request No. 98, submitted on 8/27/81, relied upon outdated test data, i.e. that associated with the Canal Fitting vs the Y-Quencher EMRV discharge header discharge device (refer to MPR-550) to incorporate staggered opening setpoints into the licensing basis of Oyster Creek. This created an unnecessarily over-conservative and inappropriately derived margin in the licensing basis of Oyster Creek. Refer to the NRC Safety Evaluation Report of Amendment 62 of the Provisional Operating License dated 7/12/92 (LS05-82-07-018).

3.0 EMRV SETPOINT BASIS/MARGIN

The purpose of this section of this Topical Report is to provide an accounting of the sources and specifics of those considerations which could be considered the reason/bases for the specific setpoint of an EMRV. These bases fall into three groups: (1) those associated with the performance of Reload Analyses (i.e., both anticipated transient and accident analyses); (2) those associated with the performance of the structural assessment of the stresses resulting from an EMRV(s) actuation; and, (3) those associated with TMI-2 lessons learned and other major nuclear industry upgrades/reevaluations. Of significance, is that the purpose and content of these reasons/bases have changed over time. This section provides a baseline for understanding and identifying the current bases for EMRV setpoints.

Historical

The below list of EMRV setpoint bases was developed by reviewing principally Amendments 65, 69 and 76 to the FDSAR, the MPR "Quick Look Report of Test on 11/24/76" dated 12/3/76, the GPUSC analysis dated 12/23/76, Reportable Occurrence No. 50-219/76-29-1P dated 1/3/77, letters to George Lear (NRC) from I. R. Finfrock (JCP&L) dated 1/10/77, the MPR "Quick Look Report of Test Results from Phase II ERV Torus Test" dated 8/17/1977, MPR Reports MPR-537, MPR-542, MPR-550, MPR-706, MPR-733, MPR-734, and, Technical Specification Change Request No. 98. These bases are:

- the high pressure actuation of the EMRVs has to be set such that the peak pressure resulting from a Turbine Trip Without Bypass, a Main Steam Line Isolation Valve Closure or a Loss of Main Condenser Vacuum is below the lowest safety valve setpoint;

- the high pressure actuation of the EMRVs has to be set such that the EMRVs will not lift subsequent to a Turbine Trip, With Bypass or Loss of Electrical Load transient;

- the high pressure actuation setpoint of the EMRVs in a given header have to be staggered by at least 20 psi to prevent more than one EMRV from discharging into a given header prior to completion of steam vent clearing in that header;

- the automatic depressurization actuation of the EMRVs has to be staggered to prevent more than one EMRV from discharging into a given header prior to completion of steam vent clearing in that header; and,

- a 50 psi difference between the high pressure actuation and closure setpoints of the EMRV in each header which has the lowest high pressure actuation setpoint has to be maintained to contribute to avoiding a second actuation of EMRVs within 3 minutes of the closure of all EMRVs in a given header.

A review of the 1972 General Electric description of the transient analyses using the revised scram reactivity curve resulted in three additional operational bases for EMRV setpoints:

- the margin between the peak pressure experienced during a Turbine Trip Without Bypass and the lowest Safety Valve Setpoint should be at least 25 psi;

- the margin between the high pressure scram setpoint and rated operating pressure should be at least 40 psi; and,

- the margin between the high pressure actuation setpoint of the EMRVs and the high pressure scram should be at least 10 psi.

Current EMRV Setpoint Basis - General

As a result of the replacement of point kinetics with 1-D kinetics to perform reload analyses and the completion of the structural revaluations utilizing the methodologies of the Mark I Containment Long Term Program, all of the above bases for EMRV actuation and/or closure setpoints are either no longer achievable, needed or have changed.

The following previous bases are no longer achievable or needed:

- The EMRVs do not have sufficient capacity to limit the peak pressure experienced during a TTWOBP to below the lowest safety valve setpoint as determined utilizing GPUN's reload analyses;

- At the current high pressure actuation setpoints, specified by Standing Order No.1, EMRV actuation(s) is expected to occur during the TTWBP as determined utilizing GPUN's reload analyses;

- The 20 psi difference between the high pressure actuation setpoints of EMRVs in a header is no longer needed;

- The staggered ADS actuation is no longer needed; and,

- The three (3) minute interval between the closure of all EMRVs in a header and a second/subsequent actuation has been replaced by a much shorter interval.

The current basis for EMRV setpoints associated with high pressure actuation (HPA) and automatic depressurization actuation (ADSA) are:

- the critical power ratio achieved during pressurization transients must be greater than the minimum critical power ratio (HPA opening setpoint);

- peak pressures experienced by the reactor vessel and recirculation system during pressurization transients must be less than ASME code allowables (HPA opening setpoint);

- the stresses, associated with EMRV actuations, must meet the structural acceptance criteria of or be appropriately dispositioned consistent with the methodologies of the Mark I Containment Long Term Program (HPA opening and closing setpoints);

- a twelve (12) second interval between the closure of all EMRVs in a header and the subsequent actuation in that header is to be provided for the small and intermediate break loss of coolant accident conditions as determined consistent with the Mark I Containment Long Term Program Loaded Definition Report (NEDO-21888) (HPA closing setpoint);

- the need to modify the ADS logic described in MPR Report No. MPR-542; and,

- 10CFR50, Appendix K criteria have to be met for loss of coolant accidents (ADSA).

Staggered/Sequential Actuation

It has been demonstrated that the Oyster Creek torus can tolerate an initial simultaneous actuation of five EMRVs followed by a subsequent simultaneous actuation of five EMRVs without taking credit for staggered actuation or operator actions. As such, the currently staggered high pressure and automatic depressurization actuation represent margin in addition to that provided by the Mark I Containment Long Term Program re-evaluation methodologies. Refer to "Steam Vent Clearing Phenomenon" in Section 4.0 of this Topical Report for additional details.

High Pressure Actuation Closure Setpoints

The 50 psi margin, between the opening and closing setpoints of the EMRVs in each header with the lowest opening setpoints, was initially associated with contributing to providing a three-minute interval between subsequent EMRV actuations with the initiation of Isolation Condensers prior to the installation of the Y-quencher and increasing of EMRV discharge header vacuum breaking capacity. The concern at that time was that because of the then vacuum breaking capacity, long water slugs could exist in the EMRV discharge header for a significant period of time (approximately three minutes) after an EMRV closure. Any subsequent actuation, with water slugs above the nominal torus water level, could generate unacceptably high stresses. Subsequent to increasing the EMRV discharge header vacuum breaking capacity, plant testing (refer to MPR Report MPR-550) determined that in all EMRV actuation sequences tested, the water slug returned to its essentially normal level within six (6) seconds after closure of the EMRV(s).

As such, a smaller margin, if any can be established. Refer to "Long Term Program" in Section 4.0 of this Topical Report for more details. Of significance here is that the as-found tolerance band of the high pressure actuation closing setpoint can probably be expanded to eliminate unnecessary operability determinations when calibrations determine that that setpoint is outside that band.

Margin to Safety Valve Actuation

Prior to Cycle 10, an operational margin of 25 psi to the lowest setpoint for safety valve actuation, during pressurization events, was being maintained. Specifically, this 25 psi margin was to be met for the Turbine Trip Without Bypass (TTWOBP) transient which provided a characterization of the plant response to the most severe pressurization event that could occur. The transient analysis of the TTWOBP was run with "licensing basis" (as opposed to "nominal") input parameters.

By letter dated November 4, 1980, the NRC notified BWR owners that the ODYN computer code would be required to be used to predict the response of the plant to pressurization transients. ODYN is a 1-D kinetics code and replaced REDY which was a point kinetics code.

Calculated peak transient pressures from the ODYN code were generally higher than those calculated by the REDY code. It was determined, utilizing the ODYN code, that the 25 psi margin could not be met for a TTWOBP transient for cycle 10. However, at the time, GE recommended a new criterion. That criterion considered only FREQUENT events using NOMINAL input parameters. At that time, these frequent events were bounded by the Main Steam Line Closure with direct scram transient. The TTWOBP transient was excluded because it was considered an INFREQUENT event. The required margin utilizing this approach was 60 psi. As part of the cycle 10 reload analysis it was determined that a 65 psi margin existed. Nominal scram speeds and Main Steam Isolation Valve times were used. It was believed that this result represented adequate margin to preclude the undesirable opening of safety valves during transient event.

As a point of emphasis, this margin to safety valve opening is a plant performance consideration and not a nuclear safety consideration. It is not considered a nuclear safety consideration because the safety valves are installed to protect against exceeding ASME code design pressures; and, reload analysis have indicated that the EMRVs have sufficient capacity to prevent exceeding ASME code requirements without safety valve actuation.

This margin to safety valve opening had been deleted from the reload analysis since cycle 10. This deletion was explicitly addressed during the review and approval of Technical Specification Change Request No. 96/Amendment 79 to the FDSAR which was approved and issued as Amendment No. 75 to the then Provisional Operating License No. DPR-16.

4.0 STEAM VENT CLEARING PHENOMENON (SVC)

The Mark I torus structure of some plants was found to be defective following cycles of Steam Vent Clearing associated with the actuation of EMRVs. The discharge of air on actuation was referred to as the SVC phenomenon. As of February 1975, investigation indicated that some plants may not have been designed to withstand this phenomenon throughout the life of the plant when the torus was subjected to a predicted number of EMRV openings. At that time, the phenomenon was characterized as a progressive material fatigue type of failure mechanism. NEDO-10859 dated April 1973 as modified by Errata and addenda dated May 21, 1973 provided an early characterization of the phenomenon and its effects.

By letter dated February 15, 1975, the NRC requested the development of a program directed towards establishing the continuing integrity of the torus. The program was to address the need for verification tests, modifications, torus fatigue characteristics, the predicted maximum number of EMRV actuation (both single and multiple) and surveillance requirements associated with verification of torus structural integrity.

The Mark I Owners Group was formed to address SVC and other issues. This Owners Group formulated what was termed the Mark I Containment Program. This program was divided into a short-term and long-term program. The Short-Term Program covered the proximate period of 1975 - 1977. The Long-Term Program (LTP) covered the proximate period of 1978 - 1984. The objective of both programs was to perform structural assessments to determine stresses caused by EMRV actuations and Loss of Coolant Accident blowdowns. What was different between the two was the methodologies used to perform the analyses and the acceptance criteria. A Load Definition Report (LDR) (NEDO-21888) approved by the NRC (NUREG-0661) was used in the LTP to define the loads associated with EMRV actuations and LOCA blowdowns. This LDR was used to perform the Oyster Creek Mark I Containment Long-Term Program Plant Unique Analysis (OCPUA).

Short Term Program

EMRV blowdown testing was performed at Monticello on June 18, 1976. Because of differences between Oyster Creek and Monticello, (i.e. different EMRV discharge header discharge device, lower torus design pressure, more than one valve discharging to a common header), similar testing was conducted at Oyster Creek on November 24, 1976. The results of that testing indicated that certain EMRV opening sequences could result in unacceptably high stresses on the torus. Reportable Occurrence No. 50-219/76-29-1P was submitted to the NRC on January 3, 1977. This Reportable Occurrence was supplemented by a letter from JCP&L to the NRC dated January 10, 1977 which provided the evaluation of the structural response of the torus to SVC based on the November 1976 test results.

The expulsion of compressed air during an EMRV(s) actuation causes the structural effect on the torus that is of concern. The magnitude of this compression is directly proportional to (1) the steam mass flow rate, (2) the length of the water slug and (3) the temperature of the discharge header piping. Item (1) is a function of the number of EMRVs that actuate and the primary system pressure at the time of actuation.

Items (2) and (3) are functions of the elapsed time since the previous EMRV(s) actuation. Based on the tests conducted on November 24, 1976, the following EMRV actuation combinations in a given EMRV discharge header were to be avoided:

1. three valve lift with cold or hot pipe;
2. two valve lift with hot pipe; and,
3. valve lift with hot pipe.

The interim action that was taken as reported on January 3, 1977 was:

1. the high pressure opening setpoint on two of the EMRVs (one in each header) was reduced to 1050 psig from 1070 psig. This 20 psi difference within a given EMRV discharge header provided the time interval/staggering needed to prevent more than one EMRV, in a specific header, from actuating until the air had been cleared during an actuation. (Note: the Technical Specification setpoint at the time was less than or equal to 1070 psig for all five EMRVs).

2. The high pressure actuation closure setpoints, of the EMRVs in each header set at 1050 psig, were reduced to 1000 psig to contribute to preventing a subsequent actuation of EMRVs in a header from occurring within three minutes of the closure of all EMRVs in that header.

3. The time delay on isolation condenser initiation was reduced to 0 to contribute to preventing a subsequent actuation of EMRVs in a header within three minutes of the closure of all EMRVs in that header. (Note: the Technical Specification setpoint at the time was less than or equal to 15 seconds).

4. The anticipatory scram on turbine trip was changed from its then setpoint of 40% of full power to 0% to contribute to preventing a subsequent actuation of EMRVs within three minutes of the closure of all EMRVs in that header.

These interim actions did not prevent the simultaneous actuation of five EMRVs (i.e. two in the north header and three in the south header) during automatic depressurization actuation. This situation was addressed by a modification to ADS which is described in MPR Report No. MPR-542. That modification consisted of:

1. addition of redundant two minute timers in each independent ADS channel;

2. addition of an ADS actuation staggering relay in each ADS channel for EMRVs NR-103B, NR-103C and NR103E; and,

3. addition of "valve open plus ADS" logic for EMRVs NR-103A and NR-103D.

In addition to modifying ADS, the EMRV discharge header discharge device was changed from the canal fitting to the Y-quencher and the discharge header vacuum breaker capacity (refer to MPR Report MPR-537) was increased during the 1977 refueling outage.

Testing of the structural response of the torus to EMRV actuations with the Y-quencher and the increase in vacuum breaker capacity was conducted in August 1977. Refer to the MPR "Quick Load Report of Test Results from Phase II Torus Test" dated 8/17/77 and MPR Report No. MPR-550 (May 1978). The comparison of these results to those of the November 1976 tests established that:

1. torus shell stresses resulting from EMRV actuation were reduced by a factor of 20 to 30;

2. vent header support column loads were reduced by a factor of 7;

3. torus shell deflections near the Y-quencher were reduced by a factor of 16 from those measured near the replaced canal fitting;

4. the deflections at the core spray suction header nozzle were reduced to zero; and

5. the increased capacity of the vacuum breakers prevented the long water slug condition which occurred in the November 1976 test; in that, the water slug returns to equilibrium in approximately six seconds versus three minutes.

These test results were used to define the loads associated with EMRV actuations in the OCPUA. Of initial significance was that the staggered/sequential initial actuation strategy was not required and subsequent actuations could be tolerated. As such, staggered setpoints are not needed to demonstrate the structural integrity of the torus consistent with NUREG-0661; and, represents margin in addition to that provided by the Long Term Program reevaluation methodologies.

Staggered Actuation

The OCPUA, utilizing the aforementioned August 1977 test results, did confirm that the Oyster Creek torus could tolerate an initial simultaneous actuation of five EMRVs followed by a subsequent simultaneous actuation of five EMRVs without taking credit for staggered initiation setpoints or operator action. As such, the EMRV actuation combinations that Reportable Occurrence No. 50-219/76-29-1P reported as being required to be avoided were no longer required to be avoided based on ASME Code (1977 Edition through Summer 1977 Addenda) limiting stress and fatigue considerations, with NRC approved exceptions.

High Pressure Actuation Closure Setpoints

Testing performed on 11/24/76 determined that long water slugs would persist in the EMRV discharge headers for a significant period of time following the closure of the EMRVs. If this condition was not mitigated, subsequent actuation of the EMRVs would result in unacceptably high stresses on the torus shell.

The evaluation of the 11/24/76 test results indicated that the time between EMRV closure and reopening had to be at least three minutes to allow the water slug to equilibrate with torus water level. To establish this three minute interval, a 50 psi differential between the opening and closing setpoint of the EMRV with the lowest opening setpoint in conjunction with a reduction in the time delay for the initiation of the isolation condensers and a reduction in the anticipatory turbine trip scram setpoint was required with the EMRV discharge header vacuum breaker capacity installed at that time.

The testing performed in August, 1977 (refer to MPR Report MPR-550) indicated that the increased vacuum breaker capacity dramatically reduced the time interval necessary for the water slug to return to nominal, i.e., approximately six seconds versus three minutes. As such, a 50 psi margin is no longer necessary to be maintained. However, subsequent analyses are apparently required to determine what margin, if any, is needed. Refer to Long Term Program below.

High Pressure/Automatic Depressurization Coordination

Depending on the size of the break, high pressure actuation of EMRVs can occur prior to automatic depressurization actuation during small break loss of coolant accidents (SBLOCA). Based on 11/24/76 test results, the high pressure and automatic depressurization actuation modes had to be coordinated to ensure that no EMRV actuations occur so close together that the water slug had not returned to its nominal level.

The ADS initiation logic was modified in 1977 to provide this coordination. It was termed the "valve open plus ADS" logic (refer to MPR Report MPR-546). This logic ensured that if an EMRV(s) actuated on high pressure during the 120 second ADS time out interval, EMRVs NR-103A and NR-103D would be locked open. Then, if ADS actuated, the other three EMRVs would discharge into EMRV discharge headers which were cleared of air avoiding the steam vent clearing phenomenon.

As discussed previously, this ADS logic modification was associated with establishing a sequential EMRV actuation strategy. As such, since this sequential actuation strategy is not needed to demonstrate the structural integrity of the torus, this logic represents margin in addition to that provided by the Long Term Program reevaluation methodologies.

Long Term Program

The Oyster Creek Plant Unique Mark I Containment Long Term Program Analysis (OCPUA) utilized computer codes to characterize the transient phenomena (loads, pressures, etc.) associated with an EMRV actuation. Two of these codes were RVFOR and RVRIZ. Refer to Technical Data Report TDR 1124 for an overview of load definition methodologies; and, MPR Reports MPR-706, MPR-723, MPR-733, MPR-734, MPR-772 and MPR-999 for an overview of the OCPUA evaluation of EMRV actuations. Also, as part of formulating the significant hazards analysis for Technical Specification Change Request No. 216, an evaluation of the change in the OCPUA resulting from increasing the setpoints of all five EMRVs from 1070 psig to 1105 psig was performed. Refer to MPR Report MPR-1434.

Of significance for this Topical Report is that the initial height of the water level in the EMRV discharge header (i.e., "the water slug") is an input parameter into RVFOR for subsequent actuations. The time history of the water slug length subsequent to an EMRV(s) closure is calculated by RVRIZ.

The assumption that there is at least a twelve (12) second interval between subsequent EMRV actuations relates to the height of the water slug that must be used as an input parameter in conducting the OCPUA for subsequent EMRV actuations. The water slug height required to be used was dependent on whether a plant unique transient analysis had been performed to determine the number of subsequent actuations to be expected and the interval between these actuations.

The interval between actuations was the dominant consideration because if it exceeded the time to peak water slug height calculated utilizing RVRIZ, the resultant stresses would be significantly reduced. The highest water slug that could reasonably be expected to occur coincident with subsequent EMRV actuations was to be used. An Oyster Creek plant unique transient analysis of the plant response to a 0.01 ft^2 and 0.1 ft^2 break was performed (refer to Technical Data Report TDR 149) as required by NUREG-0661. That transient analysis demonstrated that

- no subsequent EMRV actuations are predicted to occur if at least one Isolation Condenser subsystem actuates;

- no subsequent actuations are predicted for the 0.1 ft^2 break even with no feedwater or isolation condensers;

- subsequent actuations are predicted to occur for breaks equal to or less than 0.01 ft^2 when Isolation Condensers are not available; and,

- the interval between subsequent actuations for the 0.01 ft^2 break with no Isolation Condensers was approximately 30 seconds.

The input into this plant unique transient analysis included EMRV opening and closing setpoints which retained the 20 psi margin between EMRVs within a header and the 50 psi margin between the opening and closing setpoints of the EMRVs in each header which had the lowest opening setpoint.

The OCPUA definition of the loads associated with EMRV actuations (refer to MPR Report MPR-706) assumed that the time between subsequent actuations for the 0.01 ft^2 (i.e. the "Small Break Accident") and the

0.1 ft^2 (i.e., the "Intermediate Break Accident") was at least twelve seconds. This assumption permitted the use of a nominal water slug (i.e, zero (0))length as input to the SBA/IBA - Steam Assumed in Drywell case of the OCPUA.

An analysis of the Turbine Trip Without Bypass transient (TTWOBP) with the current as set opening (1060/1080 psig) and closing (1010/1058 psig) setpoints was conducted to support Technical Specification Change Request (TSCR) No. 216 (Calculation C-1302-411-5411-052). That analysis was run to confirm that the aforementioned twelve second interval was currently being met. The TTWOBP was chosen in lieu of the previously performed SBA/IBA analysis (i.e., TDR-149) for the following reasons:

- the subsequent EMRV actuations associated with the 0.01 ft^2 break are high pressure actuations prior to automatic depressurization actuation;

- current NRC approved GPUN reload analysis methods could be utilized;

- the TTWOBP is functionally equivalent to the TDR-149 analysis in that no isolation condenser operation or feed water injection occurs during the TTWOBP transient analysis;

- if a high pressure actuation occurs during ADS timeout, at least one valve in each header will be locked open;

- energy is dissipated only through the EMRVs versus through the EMRVs and the break; and,

- the TTWOBP is currently the most severe pressurization transient from a licensing bases perspective.

The results of this TTWOBP analysis indicated that the time interval to a subsequent actuation would exceed 12 seconds with margin.

As previously mentioned, the EMRV setpoints utilized as inputs into both the TDR-149 and the aforementioned TTWOBP analysis (C-1302-411-5411-052) retained the 20 psi margin between the opening setpoints of the EMRVs within a header and the 50 psi margin between the opening and closing setpoint of the EMRV with the lower opening setpoint in a header. The 20 psi margin is not associated with the aforementioned 12 second interval; the 50 psi margin is. A small margin, if any at all, between the opening and closing setpoints of the EMRVs with the lower opening setpoint could be used based on the following:

- the calculated intervals (i.e. TDR 149) indicate that the 50 psi margin provides approximately 30 versus 12 second interval;
- testing at 1020 psig had indicated that in all cases tested the water slug will return to its essentially normal level within six (6) seconds after closure of an EMRV(s); and,
- calculations, utilizing LDR methodology (refer to MPR-706), indicate that the water slug will return to its nominal level in approximately four (4) seconds for the SBA/IBA Steam in the Drywell case.

As a point of emphasis, before the closing setpoint can be increased, an analysis has to be performed to confirm that at least a twelve (12) second interval between subsequent actuations is maintained. As a further note, a reduction in this 12 second interval may require the rerunning of RVRIZ for Oyster Creek.

5.0 ITEMIZATION AND RESOLUTION OF OTHER EMRV ISSUES

A detailed review of the licensing basis of Oyster Creek resulted in identifying the following EMRV related issues and their resolution. The objective of this review was to identify EMRV issues whose resolution was EMRV setpoint dependent.

EMRV Inlet Nozzle Failures

Instances of relief valve inlet nozzle failures were experienced on the secondary side of a steam generator of a pressurized water reactor. The cause of failure was attributed to not considering transient flow reaction loads associated with relief valve actuation in the design of the nozzles attaching the valve to the main steam header. In view of these incidents, the AEC requested, by letter dated 4/21/72, that a reevaluation of the stress analysis of the safety and relief valve installation be performed.

An analysis of the safety valve and EMRV inlet nozzle stresses was performed and documented in MPR-369 (January 1973). For the EMRVs, the Bijlaard Method of Welding Research Council Bulletin 107 utilizing a Main Steam Header pressure of 1125 psig. That was the Technical Specification setpoint limit at that time. Refer to "EMRV Discharge Header Anchorages/Restraints" below.

Torus Baffle Damage

By letter dated 4/11/72, the AEC notified JCP&L of the damage to torus baffles discovered at the Monticello plant during inspection of the torus. Structural damage to the anchorages of the blowdown discharge pipes was also discovered. All the torus baffles were removed.

Since the design pressure of the Oyster Creek torus was lower than Monticello plant, the AEC requested that, if the baffles were going to be removed from Oyster Creek, then an analysis would be required demonstrating that removal of the torus baffles would not result in overpressurization of the torus.

The AEC also requested a report of the planned torus inspections that were going to be conducted during the refueling outage scheduled to start that month (4/72) and an analysis of the effects of all blowdown forces on the torus baffles, other torus structural components and blowdown vent pipe anchorages.

By letter dated June 2, 1972, a report entitled "Torus Baffles - Inspection and Repair Report," was submitted to the AEC. Commitments to reinspecting the remaining baffles subsequent to an EMRV lift was also made.

The Mark I Containment Long Term Program reevaluated the effects of a blowdown associated with large break loss of cooling accident and EMRV actuations. Refer to the discussions in the EMRV Discharge Header Restraints, Steam Vent Clearing Phenomenon and Suppression Pool Dynamic Phenomenon in this Topical Report; and Technical Data Report TDR 1124.

EMRV Discharge Header Anchorages/Restraints

By letters dated April 11, 1972, July 6, 1972 and September 10, 1975, the NRC requested the performance of an analysis to confirm the adequacy of the EMRV discharge header anchorages/restraints. This request was motivated by the replacement of these restraints at some plants due to design inadequacies. The September 10, 1975 letter also confirmed an NRC request that the EMRVs and their restraints be inspected for indications of damage or degradation if no inspections of this type had previously been performed subsequent to an EMRV blowdown(s).

MPR Report Nos. MPR-369 and MPR-394 document the initial and final reevaluations and reanalyses of the EMRV discharge header with the canal fitting. By letters dated August 22, 1972 and October 31, 1975 a summary of these analyses and the results of inspections were reported to the NRC. Of significance was that the reaction forces associated with EMRV actuation(s) had not been considered in the original design.

The final analysis reported that the south header was slightly overstressed during simultaneous actuation of the three EMRVs that relieve into that header. Hydraulic snubbers and rigid supports were installed and spring hangers were modified in June 1972 and May 1973 to eliminate the overstressed condition. Of significance is that the structural acceptance criteria used was ANSI B31.1.0-1967.

The magnitude of the reaction forces is dependent on the steam mass flow rate and therefore the actuation setpoint. However the analysis reported by MPR Reports Nos. MPR-369 (January 1973) and MPR-394 (October 1973) are no longer relevant for demonstrating the structural adequacy of the EMRV discharge header and restraints. The primary reasons are (1) the canal discharge fitting has been replaced by a Y-quencher and (2) the structural acceptance criteria subsequently used for the Mark I Containment Long Term Program was the 1977 edition of ASME Section III through Summary 1977. Refer to NEDO-24583, Revision 1.

The analysis that demonstrates the structural adequacy of the EMRV discharge header and restraints is described in MPR Report Nos. MPR-706, MPR 734, MPR-772 and MPR-999. Refer to Section 4.0 of this Topical Report.

Steam Quenching Vibration Phenomenon (SQV)

Severe torus structural vibrations were experienced at two European plants during prolonged EMRV operation with moderate to high EMRV steam mass flow rates. The discharge lines did not have a discharge device.

The cause of these vibrations was determined to be the development of an unsteady steam condensation condition when the pool temperature in the vicinity of the discharge line exceeded some critical value.

Regulatory Operations Bulletin 74-14 (November 13, 1974) as supplemented by letter from the NRC to JCP&L dated February 15, 1975 requested:

1. A review of operating procedures associated with events in which relief valves can't be closed to determine whether they should be modified in the following areas:

    a. limiting bulk suppression pool temperatures during normal operation and during controllable transients.

    b. requiring reactor trip if the bulk suppression pool temperature exceeds that established as a limit for controllable transients or if the EMRV(s) fails to reseat properly.

    c. taking prompt steps, in case of inadvertent EMRV actuation of failure to reseat, to minimize the duration of steam discharge to the suppression pool.

    d. promptly initiating suppression pool circulation, in cases of relief valve discharge, to dissipate local peaking of water temperatures.

    e. conducting internal and external visual inspection of the suppression pool structure for evidence of damage in instances where one or more EMRV(s) fail to reseat properly or discharges to the suppression pool for an extended period of time.

2. proposed changes to the Technical Specification to preclude the development of elevated temperatures of the torus pool; and,

3. proposed changes to the Technical Specifications to provide for inspection of the torus as appropriate to identify any damage in the event of extended EMRV(s) operation.

By letters from the NRC to JCP&L dated October 6, 1975 and December 11, 1975, the NRC took regulatory action to modify 3.5.A.1 and 3.5.A.6 of the Technical Specification to address items 2 and 3 above. Also, the October 6, 1975 letter indicated that operating procedures associated with responding to inadvertent opening or stuck open EMRV events were expected to define operator actions which are directed toward the:

1. use of all available means to close the valves;
2. initiation of suppression pool cooling;
3. initiation of a reactor shutdown; and,
4. the selection of EMRVs for actuation in such a way to assure mixing and uniformity of energy insertion.

Subsequent to the above Mark 1 Containment short term actions, effort was directed toward formulating a suppression pool temperature limit and improving the suppression pool temperature monitoring system. As of December 1977, the bases for this effort was NEDE 21078P; and, a request for supplemental generic information from GE and plant specific information from JCP&L by the NRC by letter dated December 9, 1977.

That December 9, 1977 letter requested figures which depicted the reactor pressure, EMRV steam mass flux and suppression pool bulk temperature versus time for specified EMRV events and a brief description of the suppression pool temperature monitoring system. The EMRV events to be analyzed were:

1. Stuck-open EMRV during power operation assuming reactor scram at ten minutes after the suppression pool reaches a bulk pool temperature of 110°F and all RHR systems are operable.

2. Same events as in (a) above with only one RHR train operable.

3. Stuck-open EMRV during hot standby assuming an initial 120°F bulk pool temperature and only one RHR train operable.

4. Automatic Depressurization System (ADS) activated following a small line break assuming an initial 120°F bulk pool temperature and only one RHR train operable.

5. Primary system is isolated and depressurized at a rate of 100°F per hour with an initial 120°F bulk pool temperature and only one RHR train operable.

TDR 187, Revision 1 (3/11/81) as supplemented by TDR 165 provides the Oyster Creek suppression pool temperature response to the above events.

NUREG-0661 (July 1980) established the requirement for a SUPPRESSION POOL TEMPERATURE LIMIT. That limit was to be the local pool temperature at which the onset of steam quenching vibration is expected to occur. That temperature was determined empirically to be 210°F. NUREG-0661 required that temperature to be 200°F.

In order to detect this local temperature, a bulk to local pool temperature difference was established by testing at Monticello. As reported by NEDE-21364-P (July 1978) this difference was 38°F when suppression pool cooling was available and 43°F when it wasn't.

Further tests were conducted at Monticello to identify methods to increase thermal mixing in the pool and reduce this bulk to local temperature difference. The results of these tests were reported in NEDE-24542-P (April 1979). As a result of modifications made to the GE T-quencher and suppression pool cooling discharge lines at Monticello, this bulk to local temperature difference was reduced to 15°F.

NUREG-0661 delineated that:

(1) The quencher hole pattern is the primary design feature for achieving smooth steam condensation;

(2) the 200°F local pool temperature limit applies to the GE T-quencher or quenchers which have an equal hole diameter and an equal or greater hole spacing;

(3) plant unique analysis of suppression pool temperature response to EMRV events will be necessary to demonstrate the suppression pool can be maintained within the 200°F local temperature;

(4) the plant specific local to bulk temperature difference was to be supported by test data from either the existing Monticello pool

temperature data; or, in plant tests which met the requirements of 2.13.8.1 of Appendix A of NUREG-0661; and,

(5) a suppression pool temperature monitoring system, which met the following NUREG-0661 requirements, was required to ensure that the suppression pool temperature limits established by the Technical Specifications were being met:

a. A sufficient number and distribution of pool temperature sensors was to be provided to provide reasonable measure of the bulk temperature; or, redundant pool temperature monitors may be located at each quencher, either on the quencher support or on the torus shell, to provide a measure of local pool temperature for each quencher device. In such cases, the Technical Specification limits for local pool temperature was to be derived from the calculated bulk pool temperature and the bulk to local pool temperature difference transient.

b. Sensors were to be installed sufficiently below the minimum water level, as specified in the plant Technical Specifications, to assure that the sensor properly monitors pool temperature.

c. Pool temperature was to be indicated and recorded in the control room. Where the suppression pool temperature limits are based on bulk pool temperature, operating procedures or analyzing equipment was to be used to minimize the actions required by the operator to determine the bulk pool temperature. Operating procedures and alarm setpoints were to consider the relative accuracy of the measurement system.

d. Instrument setpoints for alarm were to be established, such that the plant was being operated within the suppression pool temperature limits discussed above.

e. All sensors sere to be designed to seismic Category I, Quality Group B, and energized from on-site emergency power supplies.

It should be noted that the suppression pool temperature monitoring system had to also meet Regulatory Guide 1.97 to the extent committed.

Based on NUTECH Report GPN-02-101, Rev. 0 (1/19/83), additional thermowells were placed in the suppression pool during the Cycle 10 Refueling Outage. Refer to SDD-232C, OCIS 402256-001 and MPR Drawing No. 1083-63-01, Sheet 1 (Rev. B) and Sheet 2 (Rev. 1). At the time it was planned to monitor local pool temperature and to modify some torus attached piping to improve thermal mixing subsequent to EMRV(s) actuation.

NEDO-30832 (December 1984) demonstrated that the suppression pool temperature limit promulgated by NUREG-0661 was in fact not necessary for plants with quencher devices. As such, the requirement to establish a plant specific bulk to local temperature difference was not required. Based on an evaluation of the applicability of NEDO-30832 to Oyster Creek, GPUN received NRC approval to cancel previously planned local suppression pool temperature monitoring and thermal mixing modifications. GPUN was then required to install a suppression pool bulk temperature monitoring system which met NUREG 0661 and Regulatory Guide 1.97, Revision 2.

TDR 823 replaced TDR 187, Rev. 1 and NUTECH Report GPN-02-101, Rev. 0 as the basis for the number and placement of RTDs. Of significance is that the TDR 823 EMRV lifting scenarios were different than those used in TDR 187 and TDR 823 utilized the Pressure Suppression Pool Mixing Code provided by NUREG/CR-3471 (October 1984). Refer to MDD-OC-664A Division I and II, SE No. 402256-03, SP-1302-54-015 (Ref. 2) and OCIS-402256-002 (Rev. 2) for further details.

The number, positioning/distribution and the algorithm selected are the characteristics which determine the effectiveness of the suppression pool temperature monitoring system in providing a reasonable measure of bulk torus temperature. As such there is no impact on this reasonableness which would result from changing high pressure or automatic depressurization opening/initiation and/or closing setpoints.

Suppression Pool Dynamic Phenomenon (SPD)

This phenomenon is associated with the blowdown to the torus resulting from a loss of coolant accident not an EMRV(s) actuation. It is mentioned in this Topical Report only for completeness. SPD, SVC and SQC were required to be addressed on both a short and long term basis. All three were incorporated into the Mark I Containment Long Term Program. Refer to the Reference Section of this report.

Qualification for Liquid/Two Phase Flow

NUREG-0737 Item II.D.1 required the re-examination of the performance capabilities of the BWR safety/relief valves.

NEDE-24988-P (October 1981) reported the analysis of the results of safety/relief valve operability tests that were conducted in accordance with an NRC approved test plan. This report as supplemented by a response to NRC questions provided by GPUN letter dated April 27, 1983 was the basis of the NRC's safety evaluation report associated with this topic transmitted by letter dated June 19, 1984.

As discussed in NEDE-24988-P, it was determined that the probability of high pressure liquid or two phase discharge through the EMRVs leading to unacceptable safety consequences was sufficiently low that testing at these conditions was not warranted.

However, the "alternate shutdown cooling mode" is an anticipated operating condition which involves liquid flow through the EMRV. This mode would consist of the core spray pump injecting water into the reactor vessel and the water is vented through the EMRVs back to the suppression pool.

This mode results from the manual actuation of the EMRVs. As such, there is no impact on these test results which would result from changing overpressurization or automatic depressurization opening/initiation and/or reset setpoints.

Reduction in Challenges to and Failure Frequency of EMRVs

NUREG 0737 Item II.K.3.6 required the conduct of a feasibility study to identify various actions and modifications which might reduce the need for the EMRVs to function (i.e. challenges) and failure frequency of EMRVs to close. A high failure rate to close indicated that a stuck open EMRV is the most likely form of a small break LOCA to be expected.

The reduction in EMRV event frequency was evaluated using three approaches:

1. reducing challenges to the EMRVs;
2. reducing the probability of an EMRV to stick open when challenged; and,
3. reducing spurious blowdowns of EMRVs.

An EMRV event frequency is generated by multiplying the expected number of EMRV actuations during the lifetime of the plant by the relative probability factor for the EMRV to stick open. The objective of this effort was to identify actions which would reduce this event frequency by a factor of ten. As reported by NEDE-24954 (June 1981) such a further reduction cannot be achieved.

The expected number of EMRV actuations (i.e. "the challenges") depends on:

1. the number of transient events which would result in the actuation of an EMRV(s);
2. the number of EMRVs which are actuated during that transient; and,
3. the number of subsequent actuations which occur.

The relative probability of a Dresser Electromatic Relief Valve to stick open was estimated to be 25% of the probability of a Three Stage Target Rock to Stick Open based on General Electric's review of operating experience and engineering judgement. A detailed review of the events associated with the Three Stage Target Rock was conducted by General Electric and Target Rock.

The evaluation of the contribution of the EMRV open and close setpoint to the reduction of either the expected number of actuations or the relative probability the EMRV will stick open did indicate that the EMRV event frequency would decrease, although minimally.

Another modification that was EMRV setpoint related was directed towards reducing the number of subsequent actuations that occur. This modification was termed the "Low-Low Set" design. It assured that only the "Low-Low Set" EMRV(s) would be involved in subsequent actuations.

Although GPUN did not commit to provide this modification, actions taken in 1977, to provide short term mitigation of the effects of the steam vent clearing, did provide an equivalent nuclear safety affect. The time delay reduction of from less than or equal to 15 seconds to 3 seconds of isolation condenser initiation as well as the reduction in the anticipatory turbine trip scram essentially eliminates subsequent actuations for routine high pressure transients. In addition, the staggered high pressure actuation open and closed setpoints provide a comparable level of assurance that a minimum number of EMRVs will be actuated on subsequent actuations.

Automatic Depressurization Logic Modifications

NUREG Item II.K.3.18 required the identification of modifications to ADS logic to provide additional protection against stuck open EMRVs and small break LOCAs outside containment. The NRC staff had approved two of the proposed options. Both involved bypassing or removing the high drywell pressure permissive. Information provided by Niagara Mohawk, informed the NRC staff that installing either of these options in plants with isolation condensers would adversely affect the performance of the isolation condensers and therefore adversely affect plant safety. Subsequently, the NRC staff determined that no modification to ADS was required and that the implementation of emergency procedures was sufficient for plants with isolation condensers to satisfy this action item.

An automatic ADS actuation inhibit function has subsequently been installed to assist the operator in inhibiting automatic ADS actuation under certain conditions. Refer to TDR 581 Revision 1 (1/5/87).

Core and Containment Spray Net Positive Suction Head Considerations

Sustained EMRV(s) operation, due to either being stuck open or cycling etc. can lead to elevated torus pool temperatures. These temperatures could have a deleterious impact on the available net positive suction head (NPSH) for the core and containment spray pumps.

Sustained EMRV(s) operation is potentially more limiting, from an available NPSH perspective, than the blowdown from a loss of coolant accident (LOCA). This situation results from the fact that a LOCA results in a torus high pressure whereas a sustained EMRV operation will not. this high pressure results in higher available NPSH at higher temperatures.

TDR 137, Revision 1 (3/11/81) reported the results of an evaluation of the effects of EMRV discharge on torus pool temperature. This evaluation was not done for NPSH considerations. It was done for establishing a basis for determining a torus pool temperature limit as part of the Mark I Containment Program (refer to Steam Quenching Vibration in Section 3). However, it was referenced by TDR 396 Revision 0 (8/30/83). Specifically, Case B-6 of TDR 137 was used.

Of significance for purposes of this TDR is that the analyses reported by TDR 187, Revision 1 were non-mechanistic. As such the results are not EMRV setpoint dependent. Additionally, S&W calculations for the available NPSH for both the containment and core spray pumps were performed using a torus pool temperature of 176°F.

Systematic Evaluation Program (SEP)

The transient reanalysis associated with the SEP Program were those associated/reported as Amendment 65, 69 and 76 and/or associated supplements of the Provisional Operating License of Oyster Creek. This transient analyses bases is no longer relevant. This determination is based on the fact that as of the Cycle 10 Reload, the point kinetics approach to reload analyses was replaced by the 1-D kinetics approach.

6.0 SAFETY EVALUATION CONSIDERATIONS

Procedure 5000-ADM-1291.01 (EP-016) provides a list of considerations for determining the effects on safety of a change to the plant. Since changing the set and/or reset setpoints associated with either the high pressure or automatic depressurization actuation mode of an EMRV(s) constitutes a change to the plant, each of these considerations were evaluated to determine which would be sensitive to changes to set and reset setpoint changes.

EP-016 also requires the rendering of determinations. These determinations are also evaluated to determine which would be sensitive to EMRV set and reset setpoint changes.

The results of this evaluation are presented below as (1) Effects on Safety; (2) Safety Assessment; and (3) Regulatory Assessment.

Effects on Safety

System Performance

The effects of a change in EMRV opening or closing setpoints on system performance that are required to be considered, depending on whether the changes are associated with High Pressure Actuation (HPA) or Automatic Depressurization Actuation (ADSA), are:

- the change in the Critical Power Ratio (CPR) associated with pressurization transients as compared to the Minimum Critical Power Ratio (MCPR) required to be maintained (HPA opening setpoint);

- the change in the peak pressure experienced by the reactor vessel and recirculation system associated with pressurization transients as compared to ASME code requirements (HPA opening setpoint);

- the change in the structural loads and fatigue usage reported in the Oyster Creek Plant Unique Analysis Reports (OCPUA) associated with the structural reevaluations performed utilizing the Mark I Containment Long Term Program methodologies (HPA opening and closing setpoints);

- the change to the time interval, between EMRV closure to EMRV reopening, as compared to that assumed for the "small and intermediate break accidents" for the OCPUA (HPA closing setpoint);

- the need to modify the ADS logic as reported by MPR Report No. MPR-542;

- the need to modify the Loss of Coolant Accident Analysis (ADSA); and/or,

- the change in the required minimum torus shell thickness, as determined utilizing ASME code methods, and the nominal thickness of the torus shell (HPA opening setpoint).

Quality Standards

The quality classification of the EMRVs is based on the function(s) provided. These functions will not change as a result of a change in the setpoints. As such, the quality classification and therefore the quality standards associated with the EMRVs will not change as a result of a setpoint change.

Natural Phenomena Protection

The seismic classification of the EMRVs is based on the function(s) provided. These functions will not change as a result of a change in the setpoints.

The EMRVs do not directly provide protection for tornadoes, hurricanes or floods. They have to be protected. As such, natural phenomena protection is not affected by a change in EMRV setpoints.

Fire Protection

The ADS/EMRV control circuits were modified to prevent a spurious EMRV actuation resulting from a fire in the control room, lower cable spreading room or 460V switchgear room. Auxiliary relays were installed to provide interlocks to prevent this spurious actuations. A change to the high pressure/automatic depressurization set and/or reset point does not affect the functioning of these auxiliary relays.

The capability to close a spuriously open EMRV was also provided. A change to the high pressure/automatic depressurization set and/or reset point does not affect this capability.

Environmental Protection

The environmental qualification status of electrical equipment associated with EMRV actuation is not dependent on the specific high pressure or automatic depressurization set and/or reset setpoints. That status is based on materials, instrument loop accuracy and/or functional requirements.

Missile Protection

3.5.1.1 of the Updated FSAR indicates that the effect of missiles originating from water lines were more limiting than those originating from steam lines. As such, although the stresses experienced by the EMRV branch connection to the Main Steam Line and the EMRV discharge header, due to the transient reaction forces generated during an actuation, are dependent on the steam pressure at actuation, the EMRV and associated piping were not considered as a source of missiles internal to the drywell.

High Energy Line Breaks

3.6, as supplemented by Appendix 3.6B, of the Updated FSAR indicates that when the break location identification criteria utilized is applied, neither the EMRV branch connection to the Main Steam Line nor the EMRV discharge header result in being selected as a pipe whip break location. Increasing the high pressure actuation setpoints of the EMRVs will result in a proportionately higher pressure distribution throughout the steam line at actuation. Therefore, the increase in the setpoints will not result in changing the pipe whip break locations previously selected.

Electrical Separation

Electrical separation is a physical plant consideration not a functional plant consideration. As such, electrical separation is not affected by a change in an EMRV actuation or reset point.

Electrical Isolation

Electrical isolation is a physical plant/circuit configuration consideration not a functional plant consideration. As such, electrical isolation is not affected by a change in an EMRV actuation or reset setpoint.

Electrical Loading

The power demand associated with an EMRV(s) actuation(s) are not dependent on the actuation or reset setpoints.

Single Failure Criteria

Single failure criteria are a system/component redundancy and circuit configuration consideration not a functional plant consideration.

The Automatic Depressurization System was modified to provide short term mitigation of the "steam vent clearing" phenomenon. This modification met single failure criteria.

Single failure protection is not dependent on actuation or reset setpoints.

Containment Isolation

The EMRVs do not provide a containment isolation function.

Materials Compatibility

Material compatibility is a physical plant consideration not a functional plant consideration. As such, a change in the EMRV actuation or reset setpoint does not raise material compatibility questions.

Water Impingement

The Oyster Creek Plant Level Criteria document, SDD-OC-000, Revision 2 requires that all plant modifications have to be evaluated for the effects of water impingement due to actuation of a water type fire suppression system. A change to an EMRV actuation or reset setpoint is not a change to the physical plant configuration. As such, a change to an EMRV actuation or reset setpoint does not raise water impingement questions.

Safety Assessment

A change to the plant, in this case setpoint changes, requires an assessment to determine if the change involves either a reduction in the margin of safety previously defined in the safety analysis report; the creation of an adverse affect on nuclear safety or safe plant operations; an increase in the probability of occurrence of an accident previously evaluated in the safety analysis report; an increase in the consequences of an accident previously evaluated in the safety analysis report; an increase in the occurrence of a malfunction of equipment important to safety previously evaluated in the safety analysis report; an increase in the consequences of a malfunction of equipment important to safety previously evaluated in the safety analysis report; the creation of the possibility of an accident of a different type than previously identified in the safety analysis report; or the creation of the possibility of a malfunction of a different type than previously identified in the safety analysis report for the reasons as stated below:

1. Involve a reduction in a margin of safety

   For a change to EMRV setpoints, there are four (4) generic dimensions to addressing this consideration. They are:

   a. pressurization events represent a challenge to fuel integrity as measured by the critical power ratio (CPR) projected to be expected during a transient or accident required to be analyzed as compared to the minimum critical power ratio (MCPR) required to be maintained;

   b. pressurization events represent a challenge to reactor coolant pressure boundary as compared to ASME code requirements associated with maintaining such a boundary;

   c. EMRV(s) actuation represents a challenge to primary containment because such actuation(s) challenge the structural integrity of the EMRV discharge headers, torus shell, torus attached piping and torus submerged structures; and,

   d. loss of coolant events represent a challenge to fuel and containment integrity as well as a radiological risk to on site personnel and the public.

   The margin of safety associated with each of the above listed considerations are bounding valve based. That means that as long as the plant response remains bounded by established quantitative values (e.g., ASME code allowables, minimum critical power ratio, etc) then "margins to safety" have not been reduced.

   The analyses performed utilizing the Oyster Creek SAFER/CORECOOL/GESTR-LOCA Loss of Coolant Accident Analysis Methodology, the NRC approved GPUN reload analysis methodology, the Oyster Creek Plant Unique Analysis utilizing Mark I Containment Long Term Program methodologies, the comprehensive review of NRC SERed GPUN positions related to industry reevaluations and upgrades would be used to determine if the margins of safety associated with the operation of the Oyster Creek Nuclear Generating Station would be reduced.

2. Adverse Affect on Nuclear Safety or Safe Plant Evaluation. Refer to item 1 above.

3. Involve an increase in the probability occurrence of an accident previously evaluated:

   The adequacy of the plant response to analyzed accidents is not sensitive to an increase in the EMRV high pressure actuation setpoint. Accidents analyzed each reload are the loss of coolant accident, fuel misloading and control rod drop accident. The high pressure actuation mode of the EMRVs does not contribute to mitigating the affects of these accidents.

   With respect to the plant response to a small break loss of coolant accident, again, the high pressure actuation mode of the EMRVs does not contribute to mitigating the affects of these events.

   For changes to ADS actuation setpoints, the loss of coolant accident analyses' would have to be reperformed/re-evaluated.

4. Involve an increase in the probability or the consequences of an accident previously evaluated.

   The probability of the occurrence or the consequence of analyzed accidents are not sensitive to the EMRV high pressure actuation setpoint. However, they are sensitive to a change in ADS actuation.

   With respect to the probability of experiencing a stuck open EMRV, which would represent an increase in the probability of a small break loss of coolant, the review of EMRV preventative maintenance results indicates that there are no high pressure actuation setpoint dependent phenomena which would increase the probability of the EMRV to stick open. The consequences of a stuck open EMRV are mitigated by the operational strategies provided by the emergency operating procedures; and, thus are not sensitive to the setpoint.

5. Involve an increase in the probability of occurrence of a malfunction of equipment

   The probability of an EMRV(s) sticking open is not setpoint dependent. Refer to item 4 above.

6. Involve an increase in the consequences of the malfunction of equipment.

   The consequences of a stuck open EMRV are not setpoint dependent. Refer to item 4 above.

7. Create the possibility of a new or different kind of accident from any accident previously evaluated.

   A new or different kind of accident from any previously evaluated is not created. This is primarily because the high pressure actuation mode of the EMRVs is a preventative not a protective function with respect to fuel cladding, reactor vessel and reactor coolant pressure boundary protection.

8. Create the possibility of a malfunction of a new or different type.

   Increasing the high pressure or automatic depressurization actuation setpoint of an EMRV does not change either the way the valve functions; its physical configuration, its method of attachment to the main steam line; its generic operational relation ship with other plant components or systems; or, the effect(s) of its operation on other plant components or systems. As such, the possibility of a malfunction of a new or different type is not created.

Regulatory Assessment

1. Compliance with Plant Technical Specifications/Operating License Requirements/Regulations

   Changes to high pressure or automatic depressurization setpoints may require changes to the Technical Specifications.

With respect to other license requirements and regulations, the detailed review of the licensing basis of the Oyster Creek Nuclear Generating Station reported by this Topical Report identified the current bases for the EMRV high pressure and automatic depressurization setpoints. As such, if the effects delineated in Section 12.0 of this Topical Report, of a change in EMRV setpoints are properly evaluated no violation of other license requirements or regulations would result from increases in high pressure or automatic depressurization opening and/or closing setpoints.

2. Radiological Safety

Assuming that the required evaluations indicate that no significant hazards are created, no additional radiological safety concerns would result from high pressure or automatic depressurization actuation setpoint changes, since neither the offsite dose to the public nor the radiological dose to plant personnel resulting from an EMRV actuation will change.

3. Changes to the Updated FSAR

Some changes to the relevant section(s) of the updated FSAR are expected.

4. Effects on the Environment

The EMRVs have no interaction with plant environmental interfaces and do not interface with either plant effluents or withdrawals.

7.0 PRESSURIZATION EVENTS

The objective for normal operation and transient events is to maintain nucleate boiling and thus avoid a transition to film boiling. Operating limits are specified to maintain adequate margin to the onset of the boiling transition. For General Electric-supplied fuel, the figure of merit utilized is the critical power ratio. Thermal margin is stated in terms of a minimum value of the critical power ratio (MCPR), which corresponds to the most limiting fuel assembly in the core.

To ensure that adequate margin is maintained, a design requirement, that moderate frequency transients caused by a single operator error or equipment malfunction shall be limited such that, considering uncertainties in manufacturing and monitoring the core operating state, more than 99.9% of the fuel rods would be expected to avoid boiling transition, was selected.

The plant-unique MCPR operating limit is obtained by addition of the absolute, maximum CPR value for the most limiting transient from rated conditions postulated to occur at the plant to the fuel cladding integrity safety limit.

Transient analysis establishes the limiting values of high pressure and overpower for the Oyster Creek plant during a fuel cycle. Analyzed events are the loss of 100°F feedwater heating (LFWH), Turbine Trip Without Bypass (TTWOBP), Main Steam Isolation Valve Closure with High Flux Scram (MSIVC), Feedwater Controller Failure (Max. Demand), (FWCF), and Control Rod Withdrawal Error (RWE).

Core-wide transient results are predicted by using the methodologies documented in Topical Reports Nos. TR-020, TR-021, TR-033, TR-040. The philosophy with respect to using the equipment performance components of this model for design and safety evaluations is to consider the performance of key components at their adverse tolerances. Circuitry delays in the reactor protection system, as well as other key equipment circuit delays, are assumed at the maximum specified values. The speed of all the control rod drives following a scram is assumed to be at the plant technical specification value. Field data have shown considerable conservatism in this key component performance.

The setpoints for the EMRVs and for the high pressure scram are assumed at their Technical Specification specified limits. Other equipment performance such as EMRV and safety valve opening characteristics, recirculation pump drive train inertia and main streamline isolation valve closing times are all assumed to be at adverse tolerances.

The peak pressure and CPR achieved during the TTWOBP and FWCF are dependent in part on the EMRV high pressure actuation setpoint.

The FWCF analysis is conducted with the EMRVs modeled at the Technical Specification specified high pressure actuation setpoint. Increasing this Technical Specification specified setpoint would require a reanalysis of the FWCF event to evaluate whether the change in the CPR and peak pressure achieved remain acceptable.

The TTWOBP analysis is conducted with EMRVs modeled at the Technical Specification specified setpoints. For this analysis the safety valves are "gagged". This transient produces the most limiting CPR and highest peak pressure for pressurization events. Increasing the Technical Specification EMRV setpoints would require a reanalysis of the TTWOBP event to evaluate whether the change in CPR and peak pressure achieved remain acceptable.

The MSIV Closure with a scram and EMRV actuation is enveloped by the TTWOBP. It is a pressurization event whose outcome (i.e. peak pressure and change in CPR) is dependent on the EMRV setpoint. However, since it is enveloped by the TTWOBP a reanalysis for increased EMRV high pressure actuation setpoints should not be required.

The "safety valve sizing transient" is analyzed to determine the adequacy of the spring loaded safety valves in preventing the reactor vessel and recirculation system from exceeding ASME code requirements. The ERMVs are "gagged" in this analysis which means that the outcome is independent of the setpoints of the EMRVs.

Technical Specification Change Request (TSCR) No. 98 (Amendment No. 62) and 216 (pending) directly address more pressurization events than TTWOBP and FWCF. This was done to maintain historical continuity with TSCR No. 98 and previous reload analyses. Strictly speaking the current NRC approved GPUN reload methodology is all that would require reanalysis for increases in Technical Specification specified EMRV high pressure actuation setpoints.

8.0 AUTOMATIC DEPRESSURIZATION EVENTS

The ADS function performed by the EMRVs provides a controlled blowdown of the primary system to rapidly reduce pressure to initiate Core Spray System injection in sufficient time to meet 10CFR50, Appendix K criteria for small break loss of coolant accidents. The break size spectrum for which ADS actuation is required is 0.025 - 0.2 ft^2.

The assumed ADS initiating signals, time delay and total flow capacity utilized to perform the Oyster Creek Loss of Coolant Accident analysis is documented in NEDC-31462P, August 1987.

The ADS modification which was performed in 1977 (refer to MPR-542) to provide staggered ADS actuation ensured that the 120 second total time delay used in the Appendix K analysis is met.

Changes to ADS initiation signals and time delay would require a change to the Technical Specifications.

9.0 ANTICIPATED TRANSIENTS WITHOUT SCRAM (ATWS) CONSIDERATIONS

The analyses that have been performed to define the basis for the response to an anticipated transient without scram (ATWS) are not sensitive to the setpoint of EMRV(s). Of significance is the rate of suppression pool heatup and the peak temperature achieved without operator action. This peak temperature must be limited. Also of concern was the consequence(s) of automatic depressurization actuation, during an ATWS, which would permit core spray to inject into an "active" core. Additionally, automatic depressurization would occur at a time when the suppression pool would have a minimal heat capacity to absorb such a blowdown.

The most limiting anticipated transients without scram are the closure of all main steam isolation valves (MSIVC) and loss of feedwater (LOFW). MSIVC is more severe than LOFW. That severity is indicated by the projection that the suppression pool would reach 212°F within approximately fifteen (15) minutes without operator action. Note that it would take thirty seven (37) minutes to inject the amount of sodium pentaborate necessary for hot shutdown.

The MSIVC ATWS event is mitigated by operator termination of main feedwater flow, initiation of containment spray, injection of sodium pentaborate and inhibiting ADS actuation. Termination of main feedwater flow and injection of sodium pentaborate is assumed to be initiated at the boron injection initiation temperature (refer to calculation C-1302-213-5450-001). Although the time to reach this temperature may be slightly sensitive to EMRV high pressure actuation setpoints, that time is not relevant to effectively mitigating this event. This judgement is considered reasonable because the analyses (Technical Data Report TDR 671) that were performed to formulate guidelines to form the basis of procedures for mitigating ATWS events demonstrates that the peak torus temperature expected is dependent almost exclusively on the success/effectiveness of operator action.

From an overpressure protection perspective, the analysis that supported License Amendment No. 150 demonstrated that an MSIV closure ATWS (8 safety valves) with recirculation pump trip (RPT) and EMRV actuation was bounded by the MSIV closure with High Flux Scram (9 safety valves) and no RPT or EMRV actuation. That analysis addressed the overpressurization limits associated with an ATWS event, and demonstrated that the ATWS transients do not have to be reanalyzed for each reload. Since the Cycle 14 reload transients were reanalyzed at the proposed TSCR 2.3.D high pressure EMRV actuation setpoints, using the GPUN reload methodology, the ATWS transients were not reanalyzed for high pressure protection evaluation.

10.0 EMERGENCY OPERATING PROCEDURE (EOP) CONSIDERATIONS

Appendix C of revision 4 of the BWR Owner's Group Emergency Procedure Guidelines identifies Plant Specific Data needed and calculational procedures for developing various limits and limit curves for the Emergency Operating Procedures. A change in the minimum pressure in the reactor vessel at which the EMRV is set to lift, as specified by Standing Order No. 1, would require the recalculation or revision of several of these limits/limit curves. Refer to Attachment 1 of this Topical Report for a list and description EMRV dependent EOP limits and limit curves.

11.0 TORUS SHELL THICKNESS/CORROSION ALLOWANCES

MPR Report, MPR-953, presents the results of analyses performed to determine the margin in the thickness of the Oyster Creek torus shell. The torus shell thickness margin is determined in order to determine the corrosion allowance for the inside and outside surfaces of the torus shell.

As part of the modifications that resulted from the OCPUA, the original coatings on the inside and outside surfaces of the torus shell were removed. Inspections of the torus shell in 1983 revealed pitting corrosion on the inside surface of the shell below the water line. Repair criteria were established which defined an acceptable effective metal loss due to corrosion based on OCPUA stress analysis results. Corroded areas not meeting the criteria were repaired by weld overlay.

After installation of the torus structural modifications and weld repair, the inside surface of the torus shell was recoated with a protective coating. No coating was applied to the outside surface of the torus shell. In 1986, general corrosion on the outside surface of the torus shell was identified. Accordingly, wall thickness measurements were taken to determine the metal loss due to the observed corrosion, and analyses were performed to determine a corrosion allowance for the torus shell.

The scope of MPR-953 was to document the basis for margin in the torus shell thickness which may be considered as a corrosion allowance. This scope included:

1. Review of OCPUA torus stress analysis results to determine the minimum thickness for which the torus shell would meet ASME Code allowable stress values. This included formally documenting the analyses and corrosion allowance criteria used.

2. Review of the manufacturers' material certificates to determine actual plate thickness and strength.

3. Determination of underthickness tolerance permitted by the ASME Code.

4. Review of the 1983 GPUN torus inspection reports to determine the maximum depths of pitting corrosion which were not weld repaired.

Torus shell thickness margins were determined based on calculated stresses, actual material properties, actual plate thicknesses, and ASME Code permitted undertolerance. The maximum corrosion depths left in the torus shell following the 1983 inspections and repairs were determined.

It was demonstrated that the calculated stress margin exceeds the maximum corrosion depth left in the torus shell for all regions of the torus. The difference between the stress margin and maximum corrosion depth can be considered as a corrosion allowance. The material property and ASME Code permitted undertolerance margins could be used to justify additional corrosion allowance if needed.

GPUN Calculation C-1302-243-5320-069 was performed, as part of supporting TSCR No. 216, to evaluate the impact of increasing the high pressure actuation setpoint of the EMRVs by 15 psig on these previously derived corrosion allowances. The results of that calculation confirm that:

- nominal shell thicknesses reduced by the corrosion allowances remains greater than the minimum thickness required for a 4% increase in the EMRV high pressure actuation setpoint; and,

- nominal thicknesses of the vent system components remains greater than the minimum thickness required for a 4% increase in the EMRV high pressure actuation setpoint.

12.0 CONCLUSION

This Topical Report has identified the current bases of the EMRV high pressure and automatic depressurization setpoints. Also, the margins associated with the high pressure actuation open and close setpoints and the logic coordination between the high pressure and automatic depressurization actuation for small break loss of coolant accidents have been characterized.

As a result of identifying the current bases of the EMRV opening and closing setpoints, the effects of a change in EMRV setpoints on system performance that are required to be considered to determine the acceptability of such changes has been identified. Those effects, depending on whether the changes are associated with high pressure (HPA) or automatic depressurization (ADSA), are:

- the change in the Critical Power Ratio (CPR) associated with pressurization transients as compared to the Minimum Critical Power Ratio (MCPR) required to be maintained (HPA opening setpoint);

- the change in the peak pressure experienced by the reactor vessel and recirculation system associated with pressurization transients as compared to ASME code requirements (HPA opening setpoint);

- the change in the structural loads and fatigue usage reported in the Oyster Creek Plant Unique Analysis Reports (OCPUA) associated with the structural reevaluations performed utilizing the Mark I Containment Long Term Program methodologies (HPA opening and closing setpoints);

- the change to the time interval, between EMRV closure to EMRV reopening, as compared to that assumed for the "small and intermediate break accidents" for the OCPUA (HPA closing setpoint);

- the need to modify the ADS logic as reported by MPR Report No. MPR-542;

- the need to modify the Loss of Coolant Accident Analysis (ADSA); and/or,

- the change in the required minimum torus shell thickness, as determined utilizing ASME code methods, and the nominal thickness of the torus shell (HPA opening setpoint).

With respect to characterizing margins, this Topical Report identifies margins in addition to that provided by Mark I Containment Long Term Program structural evaluation methodologies. That additional margin(s) resulted initially from increasing the vacuum breaking capacity of the EMRV discharge header (1977) and installing the "Y-quencher" EMRV discharge header discharge device (1977) and subsequently by increasing the natural frequency of the torus through the installation of the hoop straps during the Cycle 10 refueling outage.

That additional margin resulted from ultimately determining that principally the torus shell could readily tolerate an initial five EMRV simultaneous actuation followed by a subsequent five EMRV simultaneous actuation. As such, the current staggered high pressure and automatic depressurization opening setpoints or relay settings provide that additional margin.

Necessary revisions to the Updated Final Safety Analysis Report (UFSAR) were also identified. These revisions are necessary to make the UFSAR more precisely consistent with the licensing bases. The revisions identified to date are associated with clarifying that the EMRVs do not have and are not currently required to have sufficient capacity to prevent safety valves from lifting during a Turbine Trip Without Bypass transient, utilizing reload analysis methodologies, and clarifying what the actual capacity of an EMRV is at 1125 psig.

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19. NUREG/CR-3471; Pressure Suppression Pool Thermal Mixing; October 1984.
20. NEDO-30832; Elimination of Limit on BWR Suppression Pool Temperature for SRV Discharge with Quenchers; December 1984.
21. LTR; RFW-0670; GPUN to NRC; Suppression Pool Local Temperature Limit; (Note: Requested Cancellation of (a) provision of suppression pool temperature monitoring local to the quenchers; and, (b) the thermal mixing modification); 10/31/85.
22. NRC Meeting Minutes; January 1986 Progress Review Meeting on Licensing; March 14, 1986.
23. Ltr; NRC to GPUN; Meeting of April 10, 1986, on Requested Cancellation of Nitrogen Purge/Vent System (TAC 59829); 5/5/86.
24. Ltr; 5000-86-0916; GPUN to NRC; Combustible Gas Control and Suppression Pool Temperature Limits; 6/16/86.
25. Ltr; 5000-86-0961; GPUN to NRC; Request for Additional Information Concerning Safety Relief Valve Discharges to the Suppression Pool; 7/22/86.
26. Ltr; 5000-86-0972; GPUN to NRC; Core Spray NPSH Calculations Supplemental Information; 8/4/86.
27. Ltr; NRC to GPUN; Torus Pool Thermal Mixing and Local Temperature

Indication - Cancellation of Modifications (TAC 60152, 60153); 10/1/86.

28. Modification Design Description MDD-OC-664; Division 1; Oyster Creek Nuclear Generating Station Suppression Pool Temperature Monitoring System; Revision 0 (5/20/86); BA-402256.
29. Installation Specification; OCIS-402256-002; Suppression Pool Temperature Monitoring System; Revision 2 (1/29/88).
30. Technical Data Report; TDR 823; Location of RTDs to Monitor Torus Bulk Water Temperature at Oyster Creek; Revision 3 (12/9/88).

Suppression Pool Dynamic Phenomenon (SPD)

1. NEDO-10320; The General Electric Pressure Suppression Containment Analytical Model; April 1971.
2. Ltr; NRC to JCP&L; Request for Information Pursuant to 10CFR 50154(f) related to Suppression Pool Hydrodynamic Loads during Loss of Coolant Accidents; 4/17/75.
3. Ltr; JCP&L to NRC; Response to 4/17/75 NRC Ltr; Schedule Related; 5/6/75.
4. Ltr; JCP&L to NRC; Schedule Related; 7/3/75.
5. Ltr; JCP&L to NRC; Schedule Related; 8/1/75.
6. NEDO-21052; Maximum Discharge Rate of Liquid-Vapor Mixtures from Vessels; September 1975.
7. Ltr; GD-75-013; JCP&L to NRC; Endorsement of NEDC-20989 Volumes I through V; Schedule Related; 10/30/75.
8. Ltr; NRC to JCP&L; Request for Information associated with NEDC-20989; Request for Information associated with the Proposed Long Term Program; 12/24/75.
9. Ltr; JCP&L to NRC; schedule related; 5/18/76.
10. Ltr; JCP&L to NRC; schedule related; 7/26/76.
11. Ltr; EA-76-737; JCP&L to NRC; Oyster Creek Nuclear Generating Station's Short Term Program - Plant Unique Torus Support System Analysis; 8/2/76.
12. Ltr; EATET-4; JCP&L to NRC; Oyster Creek Nuclear Generating Station's Short Term Program - Plant Unique Torus Attached Piping Analysis; 9/1/76.
13. Ltr; NRC to JCP&L; Request for Additional Information associated with the Oyster Creek Nuclear Generating Station's Short Term Program - Plant Unique Torus Support System Analysis/ 9/1/76.
14. Ltr; EAKRG-22; JCP&L to NRC; Response to the NRC's 9/1/76 Request for Additional Information; 9/16/76.
15. Ltr; NRC to JCP&L; Related to Operation with a specified Differential Pressure between the Drywell and Torus; and,

Operation near the Minimum Torus Water L[illegible]l; 9/30/76.

16. Ltr; GE to NRC; Mark I Short Term Program Report; 10/11/76.
17. Ltr; GD-76-035; JCP&L to NRC; Submitted the Results of an Evaluation of the Effects of Operation at Torus Water Levels Different from Those Assumed in the Short Term Program - Plant Unique Analysis Reports submitted on 8/2/76 and 9/1/76; 10/14/76.
18. Ltr; EATJM-172; JCP&L to NRC; Technical Specification Change Request No. 52; 12/17/76.
19. Ltr; NRC to JCP&L; Request to Revise Technical Specification Change Request No. 52 to provide commitments which are consistent with the NRC's Staff Technical Position; 2/4/77.
20. Ltr; EAKRG-141; JCP&L to NRC; Drywell to Torus Differential Pressure Instrumentation; 3/3/77.
21. Ltr; JCP&L to NRC; Failure to Maintain Drywell to Torus Differential Pressure; 3/3/77.
22. Ltr; NRC to GE; Mass and Energy Release Model for Mark I Long Term Program; 5/11/77.
23. Ltr; NRC to JCP&L; Provides Revised NRC's Staff Technical Position associated with Drywell-Wetwell Pressure Controls; 5/18/77.
24. Ltr; EAKRG-372; JCP&L to NRC; Drywell to Torus Differential Pressure; 6/20/77.
25. Ltr; EAKRG-584; JCP&L to NRC; Technical Specification Change Request No. 52 Revision 1; 9/20/77.
26. NUREG-0408, Mark I Containment Short Term Program Safety Analysis Report, December 1977.
27. Ltr; NRC to JCP&L; Transmits Amendment 32 of the Provisional Operating License; 6/20/78.
28. NEDO-21888; Mark I Containment Program Load Definition Report; Revision 0, December 1978.
29. Ltr; NRC to All BWRs; Confirmatory Requirements Relating to Condensation Oscillation Loads for the Mark I Containment Long Term Program; 10/2/79.
30. Ltr; NRC to JCP&L; Acceptance Criteria for the Mark I Containment Long Term Program; 10/31/79.
31. NEDO-24583; Mark I Containment Structural Acceptance Criteria Plant-Unique Analysis Applications Guide; Revision 1; December 1979.
32. NUREG-0484; Methodology for Combining Dynamic Responses; Revision 1, May 1980.
33. NUREG-0661; Mark I Containment Long Term Program Safety Evaluation Report; July 1980.
34. Ltr; NRC to JCP&L; Transmittal of NUREG-0661, July 1980; 8/20/80.

35. MPR-733; Oyster Creek Nuclear Generating Station Mark I Containment Long-Term Program Plant Unique Analysis Report Suppression Chamber and Vent System; August 1982.
36. MPR-734; Oyster Creek Nuclear Generating Station Mark I Containment Long-Term Program Plant Unique Analysis Report Torus Attached Piping, August 1982.
37. Ltr; GPUN to NRC; Oyster Creek Mark I Containment Long Term Program Plant Unique Analysis of the Oyster Creek Torus; 9/24/82.
38. Ltr; LS05-83-04-030; NRC to GPUN; Request for Information, Structural Review, 4/14/83.
39. MPR-772; Oyster Creek Nuclear Generating Station Mark I Containment Long-Term Program Plant Unique Analysis Supplemental Report; July 1983.
40. Ltr; GPUN to NRC; MPR Report 772, "Oyster Creek Nuclear Generating Station Mark I Containment Long-Term Program Plant-Unique Analysis Supplemental Report; 8/9/93.
41. Ltr; GPUN to NRC; Response to Requests for Information; 9/14/83.
42. Ltr; LS05-84-01-015; NRC to GPUN; NRC's Safety Evaluation Report associated with the Mark I Containment Long Term Program - Structural Review Including the Technical Evaluation Report prepared by the Franklin Research Center; 1/13/84.
43. Ltr; LS05-84-01-016; NRC to GPUN; NRC's Safety Evaluation Report associated with the Mark I Containment Long Term Program - Pool Dynamic Loads Including the Technical Evaluation Report prepared by the Brookhaven National Laboratory; 1/13/84.
44. Ltr; GPUN to NRC; Evaluation of Overstress Conditions Identified during NRC Inspection 50-219/88-15 during May 23-27, 1988; 6/1/88.
45. NRC Inspection Report 50-219/88-15; 8/19/88 (included GPUN overheads presented at a meeting on 7/26/88).
46. Ltr; 5000-88-1635; GPUN to NRC; NRC Inspection 50-219/88-15 Notice of Violation Response; 9/19/88.
47. Ltr; 5000-88-1647; GPUN to NRC; Transmitted MPR-999, Revision 1 (December 1987), "Addendum to MPR 734, Plant Unique Analysis Report, Torus Attached Piping; 10/14/88.
48. MPR-999; Oyster Creek Nuclear Generating Station Mark I Containment Long-Term Program Addendum to MPR-734 Plant Unique Analysis Report Torus Attached Piping; Revision 3 (December 1988).

Qualification for Liquid/Two Phase Flow

1. NUREG-0462; Technical Report on Operating Experience with BWR Pressure Relief Systems; July 1978.
2. NUREG-0578; July 1979; Recommendation 2.1.2; Performance Testing of BWR and PWR Relief and Safety Valves.
3. NUREG-0737; November 1980; Item II.D.I; Safety/Relief Valve Testing.
4. NEDE-24988-P; Analysis of Generic BWR Safety/Relief Valve Operability Test Results; October 1981.
5. Ltr; NRC to GPUN; Safety/Relief Valve Testing - Request for Information; 12/17/82.
6. Ltr; GPUN to NRC; Safety/Relief Valve Testing; 4/27/83.
7. Ltr; LS05-84-06-031; NRC to GPUN; transmits the NRC's Safety Evaluation Report for NUREG-0737 Item II.D.1, Safety and Relief Valve Testing;

Reduction in Challenges to and Failure Frequency of EMRVs

1. NUREG-0737; November 1980; Item II.K.3.16; Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification.
2. NEDO-24951; BWR Owner's Group NUREG-0737 Implementation: Analyses and Positions Submitted to the USNRC; June 1981.
3. NEDE-24954; BWR Owners Group Evaluation of NUREG-0737 Item II.K.3.16: Reduction of Challenges and Failures of Relief Valves - Supplement for Utility Use; June 1981.
4. Ltr; LS05-84-14-015; NRC to GPUN; Transmits the NRC's Safety Evaluation Report for NUREG-0737 Item II.K.3.16; Requests the extent to which the NRC's staff endorsed modifications will be adopted; 4/11/84.
5. Ltr; GPUN to NRC; Responds to NRCs letter of 4/11/84; 10/3/84.
6. Ltr; LS05-84-10-029; NRC to GPUN; NRC Notification of Acceptable Resolution of NUREG-0737 Item II.K.3.16 for the Oyster Creek Plant; 10/23/84.

Automatic Depressurization Logic Modification

1. NUREG-0737; November 1980; Item II.K.3.18; Modification of Automatic Depressurization System Logic - Feasibility for Increased Diversity for some event sequences.
2. NEDO-24951; BWR Owners' Group NUREG-0737 Implementation Analyses and Positions Submitted to the USNRC; June 1981.

3. Ltr; GPUN to NRC; NUREG 0737 Item II.K.3.8; 1/7/83.
4. Ltr; NRC to GPUN; Transmits NRC's Safety Evaluation Report for NUREG Item II.k.3.8; Requests Choosing One of Two Proposed Modifications; 6/3/83.
5. Ltr; GPUN to NRC; Response to NRC's 6/3/83 Letter; sates that a risk assessment will be performed; 9/1/83.
6. Ltr: GPUN to NRC; Provides Risk Assessment; 8/31/84.
7. Ltr; LS05-85-01-003; NRC to GPUN; Notifies GPUN of the acceptable resolution of NUREG-0737 Item II.k.3.8 for the Oyster Creek Nuclear Generating Station; 1/4/85.
8. Technical Data Report; TDR 581; Functional and Design Criteria for ADS Logic Manual Inhibit Switch; Revision 1 (1/5/87).

Appendix R Considerations

1. GPUN Memo; SAPC #111; OCNGS Alternate Shutdown System Evaluation on Spurious EMRV Opening - BA 402050; TR 29966; June 6, 1983.
2. Technical Data Report; TDR 350; Selection of Controls and Instrumentation for the Oyster Creek Remote Shutdown System; Revision 2 (5/1/85).
3. Safety Evaluation; SE-402635-002; Appendix R Modifications to Electromatic Relief Valves; Revision 3 (9/4/86).
4. Safety Evaluation; SE-402728-007; Appendix R Deviations - EMRV Disable Control Switches and Reactor Cleanup System Isolation Valves; Revision 3 (2/23/89).
5. Safety Evaluation; SE-402728-009; Modification of Appendix R Shutdown Path for Reactor Building Elevation 51'
6. System Design Description; SDD-OC-064A; Division I; Appendix R Modifications to Electromatic Relief Valves; Revision 2 (6/25/86).
7. System Design Description; SDD-OC-064A; Division II (Final); Appendix R Modifications to Electromatic Relief Valves; Revision 5 (8/4/88).
8. Installation Specification; OCMM-402728-007; Appendix R Deviations -EMRV Disable Control Switches and Reactor Cleanup System Isolation Valves; Revision 1 (10/14/88).

Environmental Qualification Considerations

1. Environmental Qualification Documentation File; EQ File No. EQ-OC-301; Dresser Electromatic Relief Valve (EMRV) Actuator; Model No. 1525VX; Revision 2 (8/2/89).
2. Environmental Qualification Documentation File; EQ File No. EQ-

OC-302; EMRV Controller-Dresser Consolidate Type 1539VX; Revision 1 (6/4/90).

3. Technical Data Report; TDR 904; Oyster Creek Equipment Qualification-Performance Evaluation of Instrumentation; Revision 0 (2/18/88).

ATWS Considerations

1. Technical Data Report; TDR 671; RELAP5 Oyster Creek ATWS; Revision 0 (4/3/86).
2. Technical Data Report; TDR 693; Assessment of NRC ATWS Rule as Applied to Oyster Creek; Revision 0 (7/26/85).
3. Technical Data Report; TDR 793; ARI Technical Assessment Report for ATWS Rule; Revision 0 (4/22/88).
4. Technical Data Report; TDR 804; ARI Setpoint Determination and Coordination with RPT Setpoint for Oyster Creek; Revision 0 (10/30/86).
5. Technical Data Report; TDR 953; Analysis in Support of SSV Reduction for Oyster Creek; Revision 2 (9/15/89); BA No. 402915.
6. Safety Evaluation; SE-402631-001; ATWS Modifications; Revision 3 (2/28/91).
7. Safety Evaluation; SE-402915-001; Safety Valve Reduction; Revision 4 (5/9/91).
8. Ltr; NRC to JCP&L; 9/1/76.
9. Ltr; JCP&L to NRC; Design of the Recirculation Pump Trip; 4/19/78.
10. Ltr; JCP&L to NRC; Recirculation Pump Trip Modification; 9/18/78.
11. Ltr; GPUN to NRC; 5000-87-1361; 10CFR50.62 ATWS Rule; 9/3/87.
12. Ltr; GPUN to NRC; 5000-87-1447; 10CFR50.62 ATWS Rule; 12/30/87.
13. Ltr; NRC to GPUN; Request for Additional Information on ATWS Review - Oyster Creek Nuclear Generating Station (TAC No. 66126); 1/19/88.
14. Ltr; GPUN to NRC; 5000-88-1547; 10CFR50.62, ATWS Rule; 4/29/88.
15. Ltr; GPUN to NRC; Technical Specification Change Request (TSCR) No. 162; 5/10/88.
16. Ltr; NRC to GPUN; Issuance of Amendment 124 (TAC No. 68198); 7/14/88.
17. Ltr; NRC to GPUN; Safety Evaluation On Oyster Creek Nuclear Generating Station Compliance with ATWS Rule 10CFR50.62 Relating to ARI and RPT Systems (TAC Nos. 59122 and 66126); 11/4/88.
18. Ltr; GPUN to NRC; 5000-88-1672; 10CFR50.62 ATWS Rule; 11/10/88.
19. NRC Inspection Report; 50-219/89-18; 9/14/89.
20. Ltr; GPUN to NRC; Technical Specification Change Request No. 181;

12/18/89.

21. Ltr; GPUN to NRC; C320-90-653; Technical Specification Change Request 181; 4/30/90.
22. Ltr; GPUN to NRC; Technical Specification Change Request No. 131, Revision 1; 10/16/90.
23. Ltr; NRC to GPUn; Implementation of Alternate Rod Injection System (ARI) Diversity Requirements in 10CFR50.62 (ATWS Rule) for Boiling Water Reactors (BWRs) - Oyster Creek Nuclear Generating Station; 1/24/91.
24. Ltr; NRC to GPUN; Issuance of Amendment 150 (TAC No. 75536); 3/16/91.
25. Ltr; GPUN to NRC; C321-91-2075; Alternate Rod Injection Implementation at OCNGS per 10CFR50.62 (ATWS Rule); 3/29/91; TAC Nos. 59122, 56126.
26. Ltr; GPUN to NRC; C321-91-2111; Exemption Request for Alternate Rod Injection (ARI) Diversity per 10CFR50.62 (ATWS Rule); 6/28/91; TAC Nos. 59122, 56126; 6/28/91.
27. Ltr; NRC to GPUN; Environmental Assessment and Finding of No Significant Impact-Exemption from Specific Technical Requirements Contained in 10CFR50.62 (c)(3) - TAC No. 80877; 9/18/91.
28. Ltr; NRC to GPUN; Exemption from Specific Technical Requirements of 10CFR50.62 (c)(3) - TAG No. 80377; 9/26/91.
29. NRC Inspection Report; 50-219/91-34; 12/18/91.
30. GE Report; NEDE-31096-P; Anticipated Transients Without Scram; Response to NRC ATWS Rule, 10CFR50.62.

Core Spray Net Positive Suction Head Considerations

1. Technical Data Report; TDR 165; Performance Evaluation of the Oyster Creek Containment Spray Heat Exchangers; Revision 0 (6/19/80).
2. Technical Data Report; TDR 187; Report on Effects of the Electromatic Relief Valve Discharge on Torus Water Temperature; Revision 1 (3/11/81).
3. Technical Data Report; TDR 396; Evaluation of Oyster Creek Core Spray Pumps NPSH; Revision 0 (8/30/83).
4. Technical Data Report; TDR 701; Evaluation of Emergency Service Water System; Revision 0 (12/12/85).
5. Technical Data Report; TDR 716; Best Estimate Analysis of Oyster Creek DBA LOCA Containment Response; Revision 3 (5/1/86).
6. S&W Calculation; 13432.15-01; Adequacy of Containment Spray System to Preclude Operation of Pumps at Runout Flow; Revision 0 (10/14/81).

7. S&W Calculation; 13432.15-02; Determination of Core Spray System Pumps Adequacy of Run Out Flow; Revision 0 (5/4/81).

8. S&W Calculation; 13432.15-03; Determination of the Maximum Torus Water Temperature and Flow Rate to Provide Adequate NPSH; Revision 1 (7/30/81).

9. S&W Calculation; 13432.15-04; Sizing of Core Spray System Main Flow Path Restricting Orifice and Evaluation of Its Impact on the Rated Flow Condition; Revision 0 (6/23/81).

10. S&W Calculation 13432.15-05; Determination of the NPSHA @ 4700 GPM with a Water Temperature of 160°F and 176°F; Revision 0 (7/22/81).

11. S&W Calculation 13432.15-06; Determination of the Core Spray Sys. Flow Rate with a 10% Increase in ΔP and the Recirc. Flow Isolated; Revision 0 (7/23/81).

12. S&W Calculation; 13432.15-07; Available NPSH for Containment Spray Pumps; Revision 0 (11/19/81).

13. Calculation; OC-5360-210-001; NPSH of Core Spray Pumps at Torus Water Temperature of 176°F; 8/18/82.

14. Calculation; C-1302-212-5360-012; Core Spray Booster Pump NZ03B Minimum Discharge Pressure to Verify Operability; 1/21/85.

15. Calculation; C-1302-212-5360-013; Core Spray System Hydraulic Analysis; Revision 1 (4/26/85).

16. Calculation; C-1302-212-5360; -016; Core Spray Pump NPSH,; Revision 0 (5/28/85).

17. Calculation; C-1302-212-5360-023; Main Core Spray Pump NPSH; Revision 1 (4/23/86).

18. Calculation; C-1302-212-5360-046; Main Core Spray Pump NPSH Available; Revision 2 (3/4/91).

19. Calculation; C-1302-212-5450-010; Core and Containment Spray Pumps NPSH Limit Curves; Revision 1 (8/8/86).

20. Calculation; C-1302-212-5450-034; Torus Temperature Response to Containment Spray Shutoff Pressure; Revision 0 (3/28/89).

21. Calculation; C-1302-21222-5450-035; Torus Temperature Response to ESW Temperature of 90°F and 75% Reactor Power; Revision 1 (9/1/89).

22. Calculation; C-1302-212-5450-036; Post LOCA Drywell Water Retention Volume; Revision 0 (9/13/89).

23. Calculation; C-1302-212-5450-038; Suppression Pool Temperature Response for Reduced Containment Spray and ESW; Revision 0 (9/20/89).

24. Calculation; C-1302-212-5450-039; Containment Response to DBA

LOCA with 3000 GPM Containment Spray and 3000 GPM ESW Flows; Revision 1 (8/6/90).

25. Calculation; C-1302-212-5450-041; Failure of Containment Spray Pump Low Drywell Pressure Auto Shutoff Following a DBA LOCA; Rev. 0 (4/17/90).
26. Calculation; C-1302-212-5450-043; Torus Temperature Response to a Loss of Cooling following a DBA LOCA; Revision 0 (6/26/90).
27. Calculation; C-1302-212-5450-044; Containment Spray System Flow Scenarios; Revision 0 (5/30/91).

Emergency Operating Procedure Considerations

1. Technical Data Report; TDR 535; Calculation of the Limit Curves and Setpoints for Use in the Oyster Creek Emergency Operating Procedures; Revision 0 (5/13/84).
2. Technical Data Report; TDR 821; Oyster Creek Emergency Operating Procedures Phase II Safety Evaluation; Revision 0 (11/5/86).
3. Safety Evaluation; SE-328048-001; Implementation of Phase II Emergency Operating Procedures; Revision 0 (11/5/86).
4. 2000-BAS-3200.01; EOP Technical Basis Document; Revision 1 (5/27/93).
5. 2000-BAS-3200.02; SBEOP User's Guide; Revision 0 (8/14/93).
6. 2000-BLN-3200.01; Plant Specific Technical Guidelines for the Symptom Based Emergency Operating Procedure; Revision 1 (5/27/93).
7. 2000-GLN-3200.02; Appendix A to the PSTGS-Justification for Deviations from Revision 4 of the BWR Owners Group Emergency Procedure Guidelines; Revision 1 (10/9/93).
8. OEI Document 8390-4; BWR Owner's Group Emergency Procedure Guidelines; Revision 4 (January 1987).
9. OEI Document 8510-5; Technical Bases of the Oyster Creek Nuclear Station Emergency Operating Procedures; Revision 0 (December 22, 1986).
10. GE Report; NEDO-30832; Elimination of Limit on BWR Suppression Pool Temperature for SRV Discharge with Quenchers; December 1984.
11. MPR Report; MPR-791; Primary Containment Structural Limits for Emergency Operating Procedures; December, 1983.
12. Calculation; C-1302-212-5450-008; Minimum Number of ERVs Required for Rapid Depressurization; 1/20/83.
13. Calculation; C-1302-212-5450-009; Minimum ERV Reopening Pressure; 1/20/83.
14. Calculation; C-1302-212-5450-010; OC EOPs: Core and Containment Spray Pumps NPSH Limit Curves; Rev. 1 (8/3/86).

15. Calculation; C-1302-213-5450-001; OC EOPS: Boron Injection Initiation Temperature; Rev. 4 (6/10/91).
16. Calculation; C-1302-220-5450-003, OC EOPS: Flooding and Depressurization Limits; Rev. 2 (6/6/91).
17. Calculation; C-1302-243-5450-010; OC EOPS: Heat Capacity Temperature Limit; Rev. 1 (6/6/91).
18. Calculation; C-1302-243-5450-012; OC EOPS: Heat Capacity Level Limit; Rev. 3 (6/6/91).
19. Calculation; C-1302-243-5450-023; OC EOPS: Primary Containment Pressure Limit; Rev. 0 (1/22/87).
20. Calculation; C-1302-243-5450-025; OC EOPS: Pressure Suppression Pressure; Rev. 1 (7/8/91).
21. Calculation; C-1302-411-5450-042; OC EOPS: SRV Tailpipe Level Limit; Rev. 0 (4/24/91).
22. Calculation; NA658-5411-002; Hot and Cold Shutdown Boron Weight; 1/1/83.

Pressurization Events

1. Topical Report; TR-020-A; Methods for the Analysis of Boiling Water Reactors Lattice Physics; Rev. 0 (January 1988).
2. Topical Report; TR-021-A; Methods for the Analysis of Boiling Water Reactors Steady State Physics; Rev. 0 (January 1988).
3. Topical Report; TR-022-A; Methods for Generation of Core Kinetics Data for RETRAN-02; Rev. 0 (May 1988).
4. Topical Report; TR-040-A; Steady-State and Quasi-Steady State Methods Used in the Analysis of Accidents and Transients; Rev. 0 (May 1988).
5. Topical Report; TR-045-A; BWR-2 Transient Analysis Model Using the RETRAN Code; Rev. 0 (November 1988).
6. Topical Report; TR-066; Oyster Creek Cycle 14 Core Operating Limits Report, Rev. 4 (December 22, 1992).
7. Topical Report; TR-090; Reload Information and Safety Analysis Report for Oyster Creek Cycle 14 Reload; Rev. 0 (December 24, 1992).
8. Safety Evaluation; SE-335400-030; Cycle 14 Core Design; Rev. 0.
9. Ltr: NRC to GPUN; Transmits the NRC's Safety Evaluation Report on Topical Report TR-020 originally submitted on 11/25/85; 11/14/1986 (TAC No. 60339).
10. Ltr: NRC to GPUN; Transmits the NRC's Safety Evaluation Report on Topical Report TR-021, Rev. 0 originally submitted on 3/25/86; 9/22/1987.
11. Ltr: NRC to GPUN; Transmits the NRC's Safety Evaluation Report

on Topical Report TR-033, Rev. 0 originally submitted on 4/15/87; 3/21/1988 (TAC No. 65138).

12. Ltr; NRC to GPUN; transmits the NRC's Safety Evaluation Report on Topical Report TR-040 originally submitted on 4/15/87; 3/21/1988 (TAC No. 54139).

13. Ltr; NRC to GPUN; transmits the NRC's Safety Evaluation Report on Topical Report TR-045 as originally submitted on 6/14/88; 10/12/1988 (TAC No. 66358).

NOTE: References 1, 2, 3, 9, 10 and 11 are provided for completeness only. References 4 and 5 should be used for increases in high pressure protection setpoint.

Automatic Depressurization Events

1. NEDC-31462-P; Oyster Creek Nuclear Generating Station Safer/Core Cool/GESTR-LOCA Loss of Coolant Accident Analysis, August 1987.

Systematic Evaluation Program

1. NUREG-0822; Integrated Plant Safety Assessment Systematic Evaluation Program Oyster Creek Nuclear Generating Station; January, 1983.
2. Ltr; NRC to JCP&L; Oyster Creek - SEP Topics XV-3, SV-4 and SV-14; 7/16/81.
3. Ltr; LS05-81-09-016; NRC to JCP&L; Oyster Creek - SEP Topic XV-19, Loss of Coolant Accidents Resulting From a Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary; 9/4/81.
4. Ltr; LS05-81-12-012; NRC to JCP&L; Oyster Creek - SEP Topics XV-7 and XV-15; 12/4/81.
5. Ltr; LS05-81-12-022; NRC to JCP&L; Oyster Creek - SEP topic XV-5; Loss of Normal Feedwater Flow; 12/7/81.
6. Ltr; LS05-81-12-024; NRC to JCP&L; Oyster Creek - SEP Topic XV-1; Decrease in Feedwater Temperature, Increase in Feedwater Flow and Increase in Steam Flow; 12/7/81.
7. Amendment 65 to the Oyster Creek Nuclear Generating Station Final Design and Safety Analysis Report; 12/7/71.
8. Amendment 76 to the Oyster Creek Nuclear Generating Station Final Design and Safety Analysis Report.
9. Supplement No. 1; Amendment 76 to the Oyster Creek Nuclear Generating Station Final Design and Safety Analysis Report; 3/25/75.

10. Supplement No. 4; Amendment 76 to the Oyster Creek Nuclear Generating Station Final Design and Safety Analysis Report; 10/20/75.

ATTACHMENT 1

EMRV Dependent Emergency Operating Procedures (EOP) Limits and Limit Curves

A. SETPOINT DEPENDENT

The following EOP limits and/or limit curves will require revisions if the lowest high pressure actuation opening setpoint is changed:

Boron Injection Initiation Temperature

This parameter establishes the conditions before which boron injection must be initiated if PRV depressurization with the reactor at power is to be precluded. The EMRV contribution to establishing these conditions is (1) the lowest EMRV high pressure opening setpoint (refer to Standing Order No. 1), (2) the EMRV contribution to the heat capacity temperature limit and (3) the EMRV contribution to the hot shutdown boron weight.

Heat Capacity Level Limit

This parameter is directed towards precluding the loss of the pressure suppression function for torus levels below the lc suppression pool water level LCO. The EMRV contribution towards achieving this objective is (1) the capability of the SRV selected for use as an EMRV (i.e. nameplate flowrate and nameplate pressure) (2) the lowest EMRV high pressure opening setpoint pressure (refer to Standing Order No. 1), (3) the minimum number of EMRVs required for emergency depressurization, (4) indirectly in that the saturation temperature for the lowest EMRV high pressure opening setpoint is needed and (5) indirectly in that the RPV pressure at the lowest EMRV high pressure opening setpoint is needed.

Heat Capacity Temperature Limit

This parameter is directed towards precluding the failure of the containment or equipment required for the safe shutdown by the plant. The EMRV contribution towards achieving this objective is (1) the capability of the SRV selected for use as an EMRV (i.e. nameplate flowrate and nameplate pressure) (2) the lowest EMRV high pressure opening setpoint pressure (refer to Standing Order No. 1), (3) the minimum number of EMRVs required for emergency depressurization, (4) indirectly in that the saturation temperature for the lowest EMRV high pressure opening setpoint is needed and (5) indirectly in that the RPV pressure at the lowest EMRV high pressure opening setpoint is needed.

Hot Shutdown Boron Weight

This parameter is directed towards maintaining the reactor in a shutdown condition, specifically under hot shutdown conditions irrespective of control rod position. The EMRV contribution to this objective is indirect. The saturation temperature of the lowest EMRV high pressure opening setpoint pressure is required.

Maximum Core Uncover Time Limit

This parameter is directed towards preventing core damage during recovery from RPV flooding. The EMRV contribution to this objective is provided through the contribution to the minimum core flooding interval. The minimum core flooding interval is derived from both (1) the capability of the SRV selected for use as an EMRV (i.e. nameplate flowrate and nameplate pressure) and (2) the lowest EMRV high pressure opening setpoint pressure (refer to Standing Order No. 1).

Maximum Run Temperature

This parameter is directed towards establishing when the RPV water level indication can be utilized during emergency operating conditions. The EMRV contribution to this objective is provided through the lowest EMRV high pressure opening setpoint (refer to Standing Order No. 1).

Minimum Core Flooding Interval

This parameter is directed towards assuring that the core has been covered before recovery from the RPV flooding evolution is completed. The EMRV contribution to the objective is associated with (1) the capability of the SRV selected for use as an EMRV (i.e. nameplate flowrate and nameplate pressure, (2) the lowest EMRV high pressure opening setpoint (refer to Standing Order No. 1), the minimum core flooding interval, and (4) the minimum number of SRVs for emergency depressurization.

Minimum Indicated Level

This parameter is directed towards establishing the condition (s) under which a RPV water level instrument may be used to determine RPV water level. The EMRV contribution to this objective is provided through the lowest EMRV opening setpoint pressure (refer to Standing Order No. 1).

Pressure Suppression Pressure

This parameter is directed towards assuring that the pressure suppression function is maintained while the RPV is at pressure. The EMRV contribution to this objective is provided through the (1) EMRV contribution to the heat capacity temperature limit; (2) the maximum suppression pool boundary load that results from EMRV actuation and (3) suppression pool water level which was assumed in determining the maximum suppression pool boundary load.

SRV Tail Pipe Level Limit

This parameter is directed towards precluding failure of the EMRV discharge header or the torus. The EMRV contribution to this objective is the EMRV high pressure opening and closing setpoint utilized to determine the structural response of the (1) EMRV discharge header, (2) quencher, (3) suppression pool boundary load and (4) torus attached piping and torus internal components to an EMRV(s) initial, subsequent and multiple actuations.

B. EMRV NAMEPLATE DEPENDENT

The following EOP limits and/or limit curves will require revisions if the nameplate rating of the EMRVs change:

Minimum Alternate RPV Flooding Pressure

This parameter is directed towards preventing core damage. It is the lowest reactor pressure vessel pressure at which steam flow through open EMRVs is sufficient to preclude any clad temperature from exceeding 1500°F. The EMRV contribution to this objective is associated with the capability of the SRV selected for use as an EMRV (i.e. nameplate flowrate and nameplate pressure).

Minimum Number of SRVs Required for Emergency Depressurization

This parameter is directed towards assuring that the reactor pressure vessel will depressurize and remain depressurized when emergency depressurization is required. The EMRV contribution to this objective is associated with the capability of the SRV selected for use as an EMRV (i.e. nameplate flowrate and nameplate pressure).

Minimum RPV Flooding Pressure

This parameter is directed towards assuring that a sufficient liquid injection to maintain EMRVs open and flood the RPV to the elevation of the main steam lines during the RPV flooding evolution when the reactor is shutdown. The EMRV contribution to this objective is associated with the capability of the SRV selected for use as an EMRV (i.e. nameplate flowrate and nameplate pressure).

C. OTHER CONSIDERATIONS

The following EOP limits and/or limit curves will require revision for specific EMRV related considerations as follows:

Minimum SRV Reopening Pressure

This parameter is associated with the capability of the SRV selected for use as an EMRV. As such, this capability is a function of the manufacturer and type of the SRV. EMRVs at Oyster Creek, when manually actuated, are electrically actuated, and do not close unless manually selected to close.

Primary Containment Pressure Limit

This parameter is directed towards precluding containment failure and core damage. The EMRV contribution to achieving this functional objective is associated with the capability of the SRV used as an EMRV. The maximum containment pressure at which the EMRV can be opened is the parameter. This is compared to the maximum containment pressure at which the containment vent valves and the reactor pressure vent valves can be opened.