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SUBJECT: Forwards addl info re TMI Action Item II. D. 1 concerning safety relief valves to justify applicability of results in BWR Owners Group Rept NEDE-24988-P, "Analysis of Generic BWR Safety/Relief Valve Operability Test Results."

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JAN 09 1986

Director of Nuclear Reactor Regulation
Attention: Ms. E. Adensam, Director
BWR Project Directorate #3
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

SUSQUEHANNA STEAM ELECTRIC STATION
ADDITIONAL INFORMATION REGARDING
TMI ACTION PLAN ITEM II.D.1
ER 100450 FILE 204-09, 834-1
PLA-2431

Docket Nos. 50-387
50-388

Dear Ms. Adensam:

In response to the request for additional information on the safety/relief valves employed at Susquehanna SES to justify the applicability of the generic test results in BWR Owners Group report NEDE-24988-P, "Analysis of Generic BWR Safety/Relief Valve Operability Test Results", the responses are attached.

If you have any questions, please contact us.

Very truly yours,

H. W. Keiser
Vice President-Nuclear Operations

Attachments

cc: M. J. Campagnone - NRC
R. H. Jacobs - NRC

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ADD:
EB (LIAW
PSB (L. HULMAN)
EICSB (SRINIVASAN)
RSB (ACTING)
FOB (VASSALLO)
AD - G. LAINAS (Ltr only)

SSES Responses to Questions Relative to SRV Testing
(TMI Action Plan Item II.D.1)

NRC QUESTION 1

The BWR/GE test program utilized a "rams head" discharge pipe configuration. Most plants utilize a "tee" quencher configuration at the end of the discharge line. Describe the discharge pipe configuration used at your plant and compare the anticipated loads in this configuration to the measured loads in the test program. Discuss the impact of any differences in loads on valve operability.

RESPONSE TO QUESTION 1

The safety/relief valve (SRV) discharge piping configuration at SSES utilizes a "tee" quencher at the discharge pipe exit. The lengths of the thirty two (sixteen per unit) 12 in., schedule 80, SRV discharge lines (SRVDL) vary from a maximum of 157 ft. to a minimum of 115 ft. The SRV test program utilized a rams head at the discharge pipe exit and a 10 in., schedule 80, pipe with a length of approximately 112'. Loads on the valve internals during the test program are larger than loads on the valve internals in the SSES plant configuration for the following reasons:

1. No dynamic mechanical loads originating at the "tee" quencher are transmitted to the valve in the SSES configuration because the flued head connection where the discharge line penetrates the diaphragm slab acts as a rigid anchor.

2. The first length of the segment of piping downstream of the SRV in the test facility was longer than the SSES piping, thereby resulting in a bounding dynamic mechanical load on the valve in the test program due to the larger moment arm between the SRV and the first elbow. The first segment length in the test facility is 12 ft. as compared to a maximum first segment length of 12 ft. in the plant configuration.

3. Dynamic hydraulic loads (backpressure) are experienced by the valve internals in the SSES configuration. The backpressure loads may be either (i) transient backpressures occurring during valve actuation, or (ii) steady-state backpressures occurring during steady-state flow following valve actuation.

    (a) The key parameters affecting the transient backpressures are the fluid pressure upstream of the valve, the valve opening time, the fluid inertia in the submerged SRVDL and the SRVDL air volume. Transient backpressures increase with higher upstream pressure, shorter valve opening times, greater line submergence, and smaller SRVDL air volume. The transient backpressure in the test program was maximized by utilizing a SRVDL air volume of 49.3 ft. (13 ft. submergence) which is less than the minimum SRVDL air volume of 88.9 ft. at SSES. The maximum transient backpressure occurs with high pressure steam flow conditions. The transient backpressure for

the alternate shutdown cooling mode of operation is always much less than the design for steam flow conditions because of the lower upstream pressure and the longer valve opening time.

(b) The steady-state backpressure in the test program was maximized by utilizing an orifice plate in the SRVDL above the water level and before the ramshead. The orifice was sized to produce a backpressure greater than that calculated for any of the SSES SRVDL's.

The differences in the line configuration between the SSES plant and the test program as discussed above result in the loads on the valve internals for the test facility which bound the actual SSES loads. An additional consideration in the selection of the ramshead for the test facility was to allow more direct measurement of the thrust load in the final pipe segment. Utilization of a "tee" quencher in the test program would have required quencher supports that would unnecessarily obscure accurate measurement of the pipe thrust loads. For the reason stated above, differences between the SRVDL configurations in SSES and the test facility will not have any adverse effect on SRV operability at SSES relative to the test facility.

Additional confirmation of the SRV operability is provided by the results of the Karlstein full-scale T-quencher test program conducted by Kraftwerk Union (KWU) for PP&L. The test facility was constructed to simulate the SRV steam blowdown conditions at SSES and as such incorporated an actual SSES Crosby 6R10 SRV that discharged into a pool of water through a SSES T-quencher. Two test series were run for discharge line lengths that corresponded to the longest and shortest line lengths at SSES. The T-quencher mounting arrangement and submergence were prototypical of SSES. First actuation and subsequent actuation tests (up to ten actuations in series) were run.

The results of these tests confirmed the SRV's ability to function and operate for the range of plant parameters (submergence, Rx pressure, line lengths, etc.) anticipated during steam discharges through the SSES SRV's. Although no water discharge tests were run, as stated above, the steam blowdown tests resulted in higher loading conditions than the water tests. Therefore, these test results can also be used to confirm SRV operability.

Section 8.0 of the Susquehanna SES Design Assessment Report (DAR) documents the Karlstein T-quencher test program.

NRC QUESTION 2

The test configuration utilized no spring hangers as pipe supports. Plant specific configurations do use spring hangers in conjunction with snubbers and rigid supports. Describe the safety relief valve pipe supports used at SSES and compare the anticipated loads on valve internals for the SSES pipe supports to the measured loads in the test program. Described the impact of any differences in loads on valve operability.

RESPONSE TO QUESTION 2

The SSES safety-relief valve discharge lines (SRVDL's) are supported by a combination of snubbers, rigid supports, and spring hangers. The locations of snubbers and rigid supports at SSES are such that the location of such supports in the BWR generic test facility is prototypical, i.e., in each case (SSES and the test facility) there are supports near each change of direction in the pipe routing. Additionally, each SRVDL at SSES has between three to five spring hangers, all of which are located in the drywell. The spring hangers, snubbers, and rigid supports were designed to accommodate combinations of loads resulting from piping dead weight, thermal conditions, seismic and suppression pool hydrodynamic events, and a high pressure steam discharge transient.

The dynamic load effects on the piping and supports of the test facility due to the water discharge event (the alternate shutdown cooling mode) were found to be significantly lower than corresponding loads resulting from the high pressure steam discharge event (see Table 4.2-1 of NEDE-24988-P). As stated in NEDE-24988-P, this finding is considered generic to all BWRs since the test facility was designed to be prototypical of the features pertinent to this issue. Furthermore, a piping analysis of the SRVDL at SSES Unit 2 for the water discharge event has been performed and the loads generated on the SRV have been found to be lower than those loads from the test facility.

During the water discharge transient there will be significantly lower dynamic loads acting on the snubbers and rigid supports than during the steam discharge transient. This will more than offset the small increase in the dead load on these supports due to the weight of the water during the alternate shutdown cooling mode of operation. Therefore, design adequacy of the snubbers and rigid supports is assured as they are designed for the larger steam discharge transient loads.

This question addresses the design adequacy of the spring hangers with respect to the increased dead load due to the weight of the water during the liquid discharge transient. As was discussed with respect to snubbers and rigid supports, the dynamic loads resulting from liquid discharge during the alternate shutdown cooling mode of operation are significantly lower than those from the high pressure steam discharge. Therefore, sufficient margin exists in the SSES piping system design to adequately offset the increased dead load on the spring hangers in an unpinned condition due to a water filled condition. Furthermore, the effect of the water dead weight load does not affect the ability of the SRVs to open to establish the alternate shutdown cooling path since the loads occur in the SRVDL only after valve opening.

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[illegible]

NRC QUESTION 3

Report NEDE-24988-P did not identify any valve functional deficiencies or anomalies encountered during the test program. Describe the impact on valve safety function of any valve functional deficiencies or anomalies encountered during the program.

RESPONSE TO QUESTION 3

No functional deficiencies or anomalies of the SRV's were experienced during the testing at Wyle Laboratories for compliance with the alternate shutdown cooling mode requirement. All of the valves subjected to test runs, valid and invalid, opened and closed without loss of pressure integrity or damage. Anomalies encountered during the test program were all due to failures of test facility instrumentation, equipment, data acquisition equipment, or deviation from the approved test procedure.

The test specification for each valve required six runs. Under the test procedure, any anomaly caused the test run to be judged invalid. All anomalies were reported in the test report. The Wyle Laboratories test log sheet for the Crosby 6R10 valve tests is attached. This valve is used in the Susquehanna Steam Electric Station.

Each Wyle test report for the respective valves identifies each test run performed and documents whether or not the test run is valid or invalid and states the reason for considering the run invalid. No anomaly encountered during the required test program affects any valve safety or operability function.

All valid test runs are identified in Table 2.2-1 of NEDE-24988-P. The data presented in Table 4.2-1 for each valve were obtained from the Table 2.2-1 test runs and were based upon the selection criteria of:

(a) Presenting the maximum representative loading information obtained from the steam run data.

(b) Presenting the maximum representative water loading information obtained from the 15°F subcooled water test data.

(c) Presenting the data on the only test run performed for the 50°F subcooled water test condition.

TABLE I

OPERABILITY TEST LOG, SRV CR-1

TEST NO.	TEST MEDIA	LOAD LINE CONFIGURATION	TEST DATE	REMARKS
401	Steam	I	3/24/81	Backpressure low, changed orifice.
402	Steam	I	3/24/81	Test Acceptable
403	Water	I	3/24/81	Test Acceptable
404	Steam	I	3/24/81	Test Acceptable
405	Water	I	3/25/81	Test Acceptable
406	Steam	I	3/25/81	Test Acceptable
407	Water	I	3/25/81	Test Acceptable

NRC QUESTION 4

The purpose of the test program was to determine valve performance under conditions anticipated to be encountered in the plants. Describe the events and anticipated conditions at your plant for which the valves are required to operate and compare these plant conditions to the conditions in the test program. Describe the plant features assumed in the event evaluations used to scope the test program and compare them to plant features at your plant. For example, describe high level trips to prevent water from entering the steam lines under high pressure operating conditions as assumed in the test event and compare them to trips used at your plant.

RESPONSE TO NRC QUESTION 4

The purpose of the SRV test program was to demonstrate that the SRV will open and reclose under all expected flow conditions. The expected valve operating conditions were determined through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. Single failures were applied to these analyses so that the dynamic forces on the SRV's would be maximized. Test pressures were the highest predicted by conventional safety analysis procedures. The BWR Owners Group, in their enclosure to the September 17, 1980 letter from D. B. Waters to R. H. Vollmer, identified 13 events which may result in liquid or two-phase SRV inlet flow that would maximize the dynamic forces on the SRV. These events were identified by evaluating the initial events described in Regulatory Guide 1.70, Revision 2, with and without the additional conservatism of a single active component failure or operator error postulated in the event sequence. It was concluded from this evaluation that the alternate shutdown cooling mode is the only expected event which will result in liquid at the valve inlet. Consequently this was the event simulated in the SRV test program. This conclusion and the test results applicable to SSES are discussed below. The alternate shutdown cooling mode of operation has been described in the response to NRC Question 5.

The BWR Owners Group identified 13 events by evaluating the initiating events described in Regulatory Guide 1.70, Revision 2, with the additional conservatism of a single active component failure or operator error postulated in the events sequence. These events and the plant-specific features that mitigate these events, are summarized in Table 1. Of these 13 events, only event #'s 1, 2, 3, 4, 7, 8, 9, 11, 12, & 13 are applicable to the SSES plant. Three events, namely event #'s 5, 6 and 10 are not applicable to SSES because the SSES design does not incorporate a HPCS system or a RCIC head spray.

For the ten remaining events, the SSES specific features, such as trip logic, power supplies, instrument line configuration, alarms and operator actions, have been compared to the base case analysis presented in the BWR Owners Group submittal of September 17, 1980. The comparison has demonstrated that in each case, the base case analysis is applicable to SSES because the base case analysis does not include any plant features which are not already present in the SSES design. For these events, Table 1 demonstrates that the SSES specific features are included in the base case analyses presented in the BWR Owners Group submittal of September 17, 1980. It is seen from Table 1, that all plant features assumed in the event evaluation are also existing features

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[illegible]

[illegible]

in the SSES plant. All features included in this base case analysis are similar to plant features in the SSES design. Furthermore, the time available for operator action is expected to be longer in the SSES plant than in the base case analysis for each case where operator action is required.

Event 7, the alternate shutdown cooling mode of operation, is the only expected event which will result in liquid or two-phase fluid at the SRV inlet. Consequently, this event was simulated in the BWR SRV test program. The SRV inlet fluid conditions tested in the BWR Owners Group SRV test program, as documented in NEDE-24988-P, are 15° to 50° subcooled liquid at 20 psig to 250 psig. These fluid conditions envelope the conditions expected to occur at SSES in the alternate shutdown cooling mode of operation.

As discussed above, the BWR Owners Group evaluated transients including single active failures that would maximize the dynamic forces on the safety relief valves. As a result of this evaluation, the alternate shutdown cooling mode is the only expected event involving liquid or two-phase flow. Consequently this event was tested in the BWR SRV test program. The fluid conditions and flow conditions tested in the BWR Owners Group test program were representative of the SSES plant specific fluid conditions expected for the alternate shutdown cooling mode of operation.

KEY:
X - Feature considered in Base Case Analysis
S - Feature in Plant Specific Design
NA - Not Applicable

PLANT FEATURES	#1 FW Cont. Fail., FW L8 Trip Failure	#2 Press. Reg. Fail.	#3 Transient HPCI, HPCI L8 Trip Failure	#4 Transient RCIC, RCIC L8 Trip Failure	#5 Transient HPCS, HPCS L8 Trip Failure	#6 Transient RCIC Hd. Spr.	#7 Alt. Shutdown Cooling, Shutdown Suction Unavailable	#8 MSL Brk OSC	#9 SBA, RCIC, RCIC L8 Trip Failure	#10 SBA, HPCS, HPCS L8 Trip Failure	#11 SBA, HPCI, HPCI L8 Trip Failure	#12 SBA, Depress. & ECCS Over., Operator Error	#13 LBA, ECCS Overf Brk Isol
High Water Level 7 Alarm	X/S		X/S	X/S	X/NA				X/S	X/NA	X/S	X/S	X/S
High Drywell Pressure Alarm													
FW Level 8 Trip	X/S	X/S											
RCIC Level 8 Trip			X/S	X/S	X/NA				X/S	X/NA	X/S		X/S
HPCS Level 8 Trip				X/NA	X/NA				X/NA	X/NA			X/NA
HPCI Level 8 Trip			X/S	X/S					X/S		X/S		X/S
HPCI/S and RCIC Initiation on Low Water Level	X/S	X/S	X/S	X/S	X/NA	X/NA		X/S	X/S				X/S
HPCI/S Initiation on High Drywell Pressure			X/S	X/S					X/S	X/NA	X/S	X/S	X/S
RCIC Initiation on High Drywell Pressure													X/S

KEY:
X - Feature considered in Base Case Analysis
S - Feature in Plant Specific Design
NA - Not Applicable
(1) - Low Pressure ECCS Pumps initiate on high drywell pressure and 446 psig Rx pressure.

PLANT FEATURES	#1 FW Cont. Fail., FW L8 Trip Failure	#2 Press. Reg. Fail.	#3 Transient HPCI, HPCI L8 Trip Failure	#4 Transient RCIC, RCIC L8 Trip Failure	#5 Transient HPCS, HPCS L8 Trip Failure	#6 Transient RCIC Hd. Spr.	#7 Alt. Shutdown Cooling, Shutdown Suction Unavailable	#8 MSL Brk OSC	#9 SBA, RCIC, RCIC L8 Trip Failure	#10 SBA, HPCS, HPCS L8 Trip Failure	#11 SBA, HPCI, HPCI L8 Trip Failure	#12 SBA, Depress. & ECCS Over., Operator Error	#13 LBA, ECCS Overf Brk Isol
Low Pressure ECCS Initiation on High Drywell Pressure												X / (1)	X / (1)
Low Pressure Initiation on Low Water Level													X / S
FW Pumps Trip on Low Suction Pressure	X / S												
HPCS Trip on High Backpressure			X / NA								X / NA		
RC[illegible] Trip on High Backpressure				X / S					X / S				
Turbine Trip on Vessel High Level	X / S	X / S											
MSIVs Closure on Low Turbine Inlet Pressure	X / S	X / S						X / S					
MSIVs Closure on High Steam Flow		X / S						X / S					
MSIVs Closure on High Steam Tunnel Temperature								X / S					

KEY:
X - Feature considered in Base Case Analysis
S - Feature in Plant Specific Design
NA - Not Applicable

PLANT FEATURES	#1 FW Cont. Fail., FW L8 Trip Failure	#2 Press. Reg. Fail.	#3 Transient HPCI, HPCI L8 Trip Failure	#4 Transient RCIC, RCIC L8 Trip Failure	#5 Transient HPCS, HPCS L8 Trip Failure	#6 Transient RCIC Hd. Spr.	#7 Alt. Shutdown Cooling, Shutdown Suction Unavailable	#8 MSL Brk OSC	#9 SBA, RCIC, RCIC L8 Trip Failure	#10 SBA, HPCS, HPCS L8 Trip Failure	#11 SBA, HPCI, HPCI L8 Trip Failure	#12 SBA, Depress. & ECCS Over., Operator Error	#13 LBA, ECCS Overf Brk Isol
MSIV Closure on High Radiation								X/S					
Reactor Scram on Turbine Trip	X/S	X/S											
Reactor Scram on Neutron Flux Monitor		X/S											
Reactor Scram on MSIVs Closure		X/S											
Reactor Scram on High Radiation								X/S					
Reactor Scram on High Drywell Pressure									X/S	X/NA	X/S	X/S	X/S
Reactor Scram on Low Water Level													X/S
Reactor Isolation on Low Water Level													X/S

NRC QUESTION 5

The valves are likely to be extensively cycled in a controlled depressurization mode in a plant-specific application. Was this mode simulated in the test program? What is the effect of this valve cycling on valve performance and probability of the valve to fail open or to fail closed?

RESPONSE TO NRC QUESTION 5

The BWR SRV operability test program was designed to simulate the alternate shutdown cooling mode, which is the only expected liquid discharge event for SSES. The sequence of events leading to the alternate shutdown cooling mode is given below.

Following normal reactor shutdown, the reactor operator depressurizes the reactor vessel by opening the turbine bypass valves and removing heat through the main condenser. If the main condenser is unavailable, the operator could depressurize the reactor vessel by using the SRV's to discharge steam to the suppression pool. If SRV operation is required, the operator cycles the valves in order to assure that the cooldown rate is maintained within the technical specification limit of 100°F per hour. When the vessel is depressurized, the operator initiates normal shutdown cooling by use of the RHR system. If that system is unavailable because the valve on the RHR shutdown cooling suction line fails to open, the operator initiates the alternate shutdown cooling mode.

For alternate shutdown cooling, the operator opens one SRV and initiates either an RHR or core spray pump utilizing the suppression pool as the suction source. The reactor vessel is filled such that water is allowed to flow into the main steam lines and out of the SRV and back to the suppression pool. The subsequent heating of the suppression pool is cooled by the RHR system in the pool cooling mode. As a result, an alternate cooling mode is maintained.

In order to assure continuous long term heat removal, the SRV is kept open and no cycling of the valve is performed. In order to control the reactor vessel cooldown rate and reactor pressure, the operator is instructed to control the flow rate into the vessel. Consequently, no cycling of the SRV is required for the alternate shutdown cooling mode, and no cycling of the SRV was performed for the generic BWR SRV operability test program.

The ability of the SSES Crosby 6R10 SRV to be extensively cycled for steam discharge conditions has been confirmed during steam discharge qualification testing of the valve by the valve vendor. In addition, as stated in the response to NRC question #1, PP&L performed additional qualification testing on the SSES SRV's via the Karlstein full-scale T-quencher test program. During these tests, single and multiple actuation tests (up to ten actuations in series) were performed to verify SRV operability. Based on the qualification testing of the SRV's, the cycling of the valves in a controlled depressurization mode for steam discharge conditions will not adversely affect valve performance and the probability of the valve to fail open or closed is extremely low.

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NRC QUESTION 6

Describe how the values of valve C_V's in report NEDE-24988-P will be used at your plant. Show that the methodology used in the test program to determine the valve C_V is consistent with your application.

RESPONSE TO NRC QUESTION 6

The flow coefficient, C_v, for the Crosby 6R10 (HB-65-BP) SRV utilized in SSES was determined in the generic SRV test program (NEDE-24988-P). The average flow coefficient calculated from the test results for the Crosby 6R10 is reported in Table 5.2-1 of NEDE-24988-P as 305 gpm/psi^{½}.

The flow coefficient for the Crosby 6R10 valve reported in NEDE-24988-P was determined from the SRV flow rate when the valve inlet was pressurized to approximately 250 psig. The valve flow rate was measured with the supply line flow venturi upstream of the steam chest. The C_v for the valve was calculated using the nominal measured pressure differential between the valve inlet (steam chest) and 3' downstream of the valve and the corresponding measured flow rate. Furthermore, the test conditions and test configuration were representative of SSES plant conditions for the alternate shutdown cooling mode, e.g. pressure upstream of the valve, fluid temperature, friction losses and liquid flow rate. Therefore, the reported C_v value is appropriate for application of the SSES plant.

The above flow coefficient of 305 gpm/psi^{½} has been used by SSES to confirm that the liquid discharge flow capacity of the SRV's would be sufficient to remove core decay heat when injecting into the reactor pressure vessel in the alternate shutdown cooling mode. The C_v value determined from the SRV test data demonstrates that the SRV's are capable of returning the flow injected by the RHR or CS pump to the suppression pool.