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Director
Office of Nuclear Reactor Regulation
U S Nuclear Regulatory Commission
Washington, DC 20555

PRAIRIE ISLAND NUCLEAR GENERATING PLANT
DOCKET NOS. 50-282 LICENSE NOS. DPR-42
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Additional Information Related to
NUREG-0737, Item II.D.1, Performance
Testint of Relief and Safety Valves

The purpose of this letter is to provide additional information related to the performance testing of relief and safety valves installed at the Prairie Island Nuclear Generating Plant. This information was requested in a letter dated February 14, 1985 from Mr James R Miller, Chief, Operating Reactors Branch #3, Division of Licensing, USNRC.

Attached are our responses to the requested information and copies of three reports referenced in our responses:

a. Pressurizer Safety and Relief Line Evaluation Summary Report - Unit 1, Westinghouse Electric Corporation, February, 1984

b. Pressurizer Safety and Relief Line Evaluation Sumary Report - Unit 2, Westinghouse Electric Corporation, February, 1984

c. Summary Report for the Evaluation of Pipe Supports for the Pressurizer Safety and Relief Line, Fluor Engineers, Inc., August 15, 1985

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Please contact us if you have any questions related to the information we have provided.

David Musolf
Manager - Nuclear Support Services

c: Regional Administrator-III, NRC
Resident Inspector, NRC
NRR Project Manager, NRC
G Charnoff

Attachments

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Attachments

In response to NRC letter of February 14, 1985, "Request for Additional Information: NUREG-0737 Item II.D.1, Performance Testing of Relief and Safety Valves", the following information is provided.

Questions Related to Selection of Transients and Inlet Flow Conditions:

1. The Westinghouse valve inlet fluid conditions report stated that liquid discharge through both the safety and Power Operated Relief Valves (PORVs) is predicted for an FSAR feedline break event. The Westinghouse report gave expected peak pressure and pressurization rates for some plants having a FSAR feedline break analysis. The Prairie Island plants were not included in this list of plants having such a FSAR analysis. Nor does the Prairie Island plant specific submittal address the FSAR feedline break event. NUREG-0737, however, requires analysis of accidents and occurrences referenced in Regulatory Guide 1.70, Revision 2, and one of the accidents so required is the feedline break. Provide a discussion on the feedwater line break event either justifying that it does not apply to this plant or identifying the fluid pressure and pressurization rate, fluid temperature, valve flow rate, and time duration for the event. Assure that the fluid conditions were enveloped in the EPRI tests and demonstrate operability of the safety and relief valves for this event. Further, assure that the feedline break event was considered in the analyses of the safety/relief valve piping system.

   Response

   The feedline break accident is not part of the Prairie Island licensing basis. Nuclear plants such as the Prairie Island units were licensed prior to issuance of Regulatory Guide 1.70, Revision 2, were not required to consider the feedline break as part of their design basis.

2. In valve operability discussions on cold overpressurization transients, the submittal only identifies conditions for water discharge transients. According to the Westinghouse valve inlet fluid conditions report, however, the PORVs are expected to operate over a range of steam, steam-water, and water conditions because of the potential presence of a steam bubble in the pressurizer. To assure that the PORVs operate for all cold overpressure events, discuss the range of fluid conditions for expected types of fluid discharge and identify the test data that demonstrate operability for these cases.

   Since no low pressure steam tests were performed for the relief valves, confirm that the high pressure steam tests demonstrate operability for the low pressure steam case for both opening and closing of the relief valves.

Response

The maximum temperature and pressure conditions that can be achieved at the PORV inlet coincidently occur for steam bubble operation. Since pressure is normally maintained below the PORV setpoint, the maximum steam and saturated liquid pressure maintained in the pressurizer during startup and shutdown operations in anticipation of the COP event would occur at the PORV setpoint. This pressure (P') and corresponding temperature (T') would be as follows:

P' (psig)	T' (deg F)
500	470

Using these conditions, the potential worst case scenarios for PORV discharge during a COP event would be:

1. Discharge of saturated steam at $P \leq P'$ and $T \leq T'$ (steam in upper part of pressurizer)

2. Discharge of saturated water at $P \leq P'$ and $T \leq T'$ (saturated water in pressurizer)

3. Discharge of subcooled water at $P < P'$ and $T < T'$ (mixing of colder RCS water with saturated pressurizer water)

4. Scenario 1 followed by Scenario 2

5. Scenario 2 followed by Scenario 3

6. Scenario 1 followed by Scenario 2 followed by Scenario 3.

EPRI Test conditions for PORV's were chosen based on expected fluid conditions. Tests were limited but designed to confirm operability over a full range of expected inlet conditions. Steam, steam to water and water flow tests were conducted. Results of these tests can be found in EPRI report EPRI NP-2670-LD, Volume 7, Table VII-3. Although steam tests were conducted only at high pressures, it is expected that satisfactory performance would also result at the less severe lower pressures. This can be confirmed by the high pressure versus low pressure water tests where successful valve operations was observed.

3. Results from the EPRI tests on the Crosby safety valves indicate that the test blowdowns exceeded the design value of 5% for both "as installed" and "lowered" ring settings. If the blowdowns expected for the plant (see Question 4) also exceed 5%, the higher blowdowns could cause a rise in pressurizer

3. (Cont.)

water level such that water may reach the safety valve inlet line and result in a steam-water flow situation. Also, the pressure might be sufficiently decreased such that adequate cooling might not be achieved for decay heat removal. Discuss these consequences of higher blowdowns if increased blowdowns are expected.

Response

The impact on plant safety of pressurizer relief valve blowdowns in excess of 5% for Prairie Island Units 1 and 2 was evaluated. The results of this evaluation showed no adverse effects on plant safety.

Relief valve blowdowns in excess of that assumed in the Prairie Island Final Safety Analysis Report (FSAR) will have the following effects on the events in which relief valve actuation occurs:

1. Increased pressurizer water level during and following the valve blowdown,

2. Lower pressurizer pressure during and following valve blowdown,

3. Increased inventory loss through the relief valve.

The impact of the increased relief valve blowdowns with respect to the above effects was evaluated for the two Prairie Island FSAR events in which relief valve actuation occurs, (i.e., Loss of Load and Locked Rotor).

For the Loss of Load event, results from sensitivity analyses performed for 4 loop plants were used for the evaluation. It is felt that very similar results would be found for 2 loop plants. These analyses investigated the effects of different blowdown rates on the Loss of Load event. The results of these analyses showed only marginal increases in pressurizer water volume and the maximum pressurizer water levels were well below the level at which liquid relief would occur. Peak RCS pressures were shown to be unaffected by the increased blowdowns. The increased blowdowns did result in lower pressurizer pressure and increases RCS inventory loss. However, these had no adverse impact on the event and adequate decay heat removal was maintained.

For the Locked Rotor event, increased relief valve blowdowns have little impact on the event. As analyzed and presented in the Prairie Island FSAR, the opening and closing of the relief valve occurs over a short time period (< 4 seconds). As a result, there is little change in either pressurizer level or RCS inventory. Increased relief valve blowdowns would have no impact on peak pressure, peak clad temperature, or DNBR, as these occur prior to closing of the relief valve.

Questions Related to Valve Operability

4. The submittal states that Westinghouse and Crosby are developing optimum ring settings for the safety valves. Identify the final ring settings selected as a result of this effort. Since EPRI tests on the Crosby 3K6 and 6M6 safety valves were used to evaluate performance of the 6M16 valve of Prairie Island, identify which EPRI tests on the 3K6 and 6M6 valves had ring settings representative of those used on the plant 6M16 valve. Identify the expected blowdowns corresponding to the plant ring settings and explain how these blowdowns were extrapolated or calculated from test data. Verify that with the ring settings used the valves can perform their pressure relief function and the plant can be safety shutdown with the blowdown, backpressure, and fluid conditions occurring at the plant.

   Response

   The safety valve ring settings used on the Prairie Island Valves were developed by Crosby during original production testing. No changes to these original ring settings were made as a result of the EPRI testing program. The valves installed at Prairie Island should have performance characteristics similar to those test valves that were tested at the "as-shipped" ring settings.

5. The Prairie Island plant Crosby 6M16 safety valve was not tested by EPRI. Results from EPRI tests on the Crosby 3K6 and 6M6 safety valves were used to evaluate performance of the Crosby 6M16 valve of Prairie Island Units 1 and 2. The EPRI test results indicate that the 6M6 valve achieved rated flow for steam flow. Though the submittal states that the 3K6 valve also achieved rated flow, the EPRI test results show that this valve had not achieved rated flow at 3% accumulation for the loop seal tests at certain ring settings. Provide a further evaluation as to whether the test results sufficiently show that the 6M16 valve will pass rated flow at the plant ring settings.

   Response

   As noted in Table 4.4 of EPRI Report NP-2770-LD, Volume 6, the Crosby 6M6 test valve achieved rated flow for each of the tests reported at 3 percent accumulation regardless of the ring setting used in the test. A review of EPRI Tables 4-3 and 4-4 in volume 5 of EPRI Report NP-2770-LD reveals that the steam tests of the 3K6 valve where blowdown was measured to be less than 10 percent, flow rates of 119-122 percent of rated flow at 3 percent accumulation were reported. The EPRI tables indicate the lower than rated flows occurred at blowdowns greater than 15 percent for the 3K6 valve. No flow data was collected for the 6N8 valve. Crosby production tests for the Prairie Island valves indicate 5 percent blowdown with the "as-shipped" ring settings. These are the ring settings currently installed on the Prairie island safety valves. This is within the range of both the 3K6 and 6M6 tests where rated flow was achieved; therefore, rated flow can be expected for the safety valves.

6. During an EPRI loop seal steam-to-water transition test on the 3K6 valve, the valve fluttered and chattered when the transition to water occurred. The test was terminated after the valve was manually opened to stop chattering. The 6M6 valve exhibited similar behavior on a subcooled water test, which was terminated after the valve was manually opened to stop chatter. Justify that the valve behavior exhibited in these tests is not indicative of the performance expected for the Prairie Island valves. Potential liquid flow through the plant safety valves cannot be disregarded unless the feedline break event is shown to be nonapplicable to this plant (See Question 1).

Response

Because of the similarity of the Prairie Island Crosby 6M16 safety valve with the tested Crosby 3K6 and 6M6 valves the 6M16 would be expected tc perform similarly to the 3K6 and 6M6 (Performance variations resulting from differences in valve inlet piping configuration for plant vs. test arrangements should be taken in account). However, liquid flow through the Prairie Island safety valve can be disregarded because the feedline break event is nonapplicable to this plant.

7. Bending moments are induced on the safety valves and PORVs during the time they are required to operate because of discharge loads and thermal expansion of the pressurizer tank and inlet piping. Make a comparison between the predicted plant moments with the moment applied to the tested valves to demonstrate that the operability of the valves will not be impaired.

Response

The maximum expected Bending Moments for the safety and relief valves at Prairie Island Units 1 and 2 are 122.720 in-Kips for the safety valves and 28.76 in-kips, for the PORVS respectively. These valves are much less than the bending moments measured by EPRI for the Crosby 6M6 (298.75 in-kips) and Crosby 3K6, (161.5 in-kips) safety valves or the Copes-Vulcan PORV (43.0 in-kip). It is therefore concluded the Prairie Island Safety and Relief valves will function properly when subjected to the anticipated loadings.

8. NUREG-0737, Item II.D.1 requires that the plant specific PORV control circuitry be qualified for design-basis transients and accidents. Please provide information which demonstrates that this requirement has been fulfilled.

Response

Electrical components required for valve operation and status indication have been qualified under 10 CFR 50.49 "Environmental Qualification of Electric Equipment Important to Safety For Nuclear Power Plants."

Questions Related To Thermal Hydraulic Analysis:

9. The submittal indicates that thermal hydraulic analysis have been completed on Prairie Island Units 1 and 2 but does not describe these analyses. Identify the computer programs used to perform the thermal hydraulic analyses and provide verification that these programs have generated accurate fluid loads for similar problems.

Response

Reports entitled "Pressurizer Safety and Relief Line Evaluation, Summary Report, Northern States Power Company, Prairie Island Nuclear Generating Station, Unit No. 1", dated February 1984 and "Pressurizer Safety and Relief Line Evaluation, Summary Report, Northern States Power Company, Prairie Island Nuclear Generating Station, Unit No. 2", also dated February 1984 discuss the analyses and evaluation conducted. Section 4 of the reports discusses the methodology employed by the thermal hydraulic programs and also demonstrates the ability of the programs to generate accurate fluids loads by comparing analytical results to EPRI test results.

10. Provide evidence that the analysis was performed on the fluid transient cases producing the maximum loading on the safety valve/PORV piping system. Identify the fluid conditions assumed including pressure, temperature, pressurization rate, fluid range, and number of valves actuated.

Response

Two valve opening cases were addressed as discussed in the reports mentioned in the response to Question 9. The two safety valves opening simultaneously and discharging without PORV flow and the two PORV's opening simultaneously without safety valve flow.

The initial conditions for the safety valve water slug discharge case included:

P (Upstream)	=	2575 psia
h (Water, Upstream)	=	1110 Btu/lb
h (Water, Upstream)	=	Enthalpy based upon a temperature profile consistent with EPRI safety valve discharge Test #917, i.e., approximately 300F at the valve inlet and saturation temperature at the steam-water interface
P (Downstream)	=	14.7 psia

The pressurizer conditions were held constant for the transient at 2575 psia and 1110 Btu/lb.

The initial conditions for the relief valve slug discharge case included:

P (Upstream)	=	2350 psia
h (Steam, Upstream)	=	1162.4 Btu/lb
T (Water, Upstream)	=	150F
P (Downstream)	=	14.7 psia

The pressurizer conditions were held constant for the entire transient at 2350 psia and 1162.4 Btu/lb.

PORV actuation, due to a pressure excursion during normal plant operation, will result in loop seal discharge followed by steam. The loop seal discharge case envelopes both the steam discharge case and any low temperature water solid case. Safety valve loop seal discharge followed by steam is the limiting design case for the safety valve discharge piping.

11. Report the flow rates through the safety valves and PORVs that were assumed in the thermal hydraulic analysis. Because the ASME Code requires derating of the safety valves to 90% of actual flow capacity, the safety valve analysis should be based on a flow rate of at least 111% of the flow rating of the valve, unless another flow rate can be justified. Provide information explaining how derating of the safety valves was handled.

Response

A time-history thermal hydraulic analysis was performed for each of the valve discharge cases analyzed. Results are presented in the reports referenced in the response to Question 9.

The nominal steam flow rating for the Crosby safety valves (orifice size 6M16), the safety valves utilized on both Prairie Island Unit No. 1 and No. 2 at 2500 psia is 345,000 lb/hr. The minimum analytically determined steam flow through each of the safety valves on either Unit No. 1 or No. 2 is greater than 420,000 lb/hr. This is equivalent to a flow of 122 percent of rated.

The maximum expected steam flow through the Copes Vulcan PORV's, the valves on both units, is 210,000 lb/hr. Values greater than 257,000 lb/hr. were calculated for Unit No. 2. This is a flow of 122 percent of rated. Flows greater than 1.20 percent of rated were ensured for Unit No. 1 by utilizing the same initial condition data and more restrictive valve parameters than that employed for the Unit No. 2 analysis.

12. The submittal indicates that the addition of insulation to the loop seals upstream of the valves was necessary to reduce the fluid loads. The loop seal temperature distribution corresponding to the insulated condition should be accurately represented in the thermal hydraulic analysis since the calculated forces could be significantly affected by the temperatures assumed. Explain how the temperature distribution was determined and provide verification of its accuracy.

<u>Response</u>

To determine the temperature distribution on the loop-seal, thermocouples were attached to the pipe under the insulation. Readings obtained, during the following power operation period, were found to closely correspond to temperatures used during the EPRI tests. The EPRI test case values were then used as input to the analysis.

Questions Related To Structural Analysis

13. The Submittal indicates that the structural analysis has been completed but does not describe the analysis. Identify the program used to perform the analysis and provide verification that the program has produced accurate results on similar problems.

<u>Response</u>

Reports noted in the response to Question 9 discuss the analyses and evaluation conducted. In the reports, a discussion of the methodology employed by the structural programs is presented. Also discussed is the ability of the programs to generate accurate analytical results by comparison to test results.

14. Identify the load combinations performed in the analysis together with allowable stress limits for piping and supports both upstream and downstream of the valves. Also, identify the governing codes and standards used to determine piping and support adequacy.

<u>Response</u>

The load combinations, stress limits and governing codes utilized for the piping analyses of the upstream and downstream piping are presented in the aforementioned reports. Additionally, the attached Fluor Engineer's, Inc. report summarizes the evaluation of the pipe supports for the pressurizer safety and relief line.

15. The submittal indicates that some modifications to the pipe supports are needed and these these modifications will be implemented in future refueling outages. Provide a comparison between calculated piping stresses and support loads with allowables for the modified piping system to verify structural adequacy of the new system.

Response

The calculated piping stresses and support loads presented in the previously mentioned reports are based upon the modified system. The modifications are complete.

16. According to the results of EPRI tests, high frequency pressure oscillations of 170-260 Hz typically occur in the piping upstream of the safety valve while loop seal water passes through the valve. The submittal refers to an evaluation of this phenomenon that is documented in the Westinghouse report WCAP 10105 and states that the acoustic pressure occuring prior to and during safety valve discharge are below the maximum permissible pressure. The study discussed in the Westinghouse report determined the maximum permissible pressure for the inlet piping and established the maximum allowable bending moment for Level C Service Conditions in the inlet piping based on the maximum transient pressure measured or calculated. While the internal pressures are lower than the maximum permissible pressure, the pressure oscillations could potentially excite high frequency vibration modes in the piping, creating bending moments in the inlet piping that should be combined with moments from other appropriate mechanical loads. Provide one of the following: (a) a comparison of the allowable bending moments established in WCAP 10105 for Level C Service Conditions with the bending moments induced in the plant piping by dynamic motion and other mechanical loads or (b) justification for other alternate allowable bending moments with a similar comparison with moments inducted in the plant piping.

Response

The piping system response for Prairie Island Unit No. 1 and No. 2, including the safety valve loop seal region, is due to frequencies less than 100 HZ. The frequency of the forces and moments in the 170-260 HZ range potentially induced by the pressure oscillations is significantly greater than this frequency. The upper limit of significant frequency content for similar systems is also much less than this (170-260 HZ) range. Industry data indicates that only frequencies of 100 HZ or less are meaningful. The EPRI data confirms this. Consequently, no significant bending moment during the pressure oscillation phase of the transient will occur.

In the previously mentioned reports, pressure stresses based upon a pressure of 2458 psig were included with the bending moments resulting for the deadweight and the safety valve discharge piping loads. Because of the time phasing of the pressure oscillation (during water slug discharge through the safety valve) and the discharge piping loads (subsequent to water slug discharge through the valve) this term and moment term were not added. They do not occur coincidentally. A comparison of the intensified bending moments from the stress evaluation and the allowable moment presented in WCAP-10105 shows that all values are below the allowables. Specifically, the maximum allowable moment from Table 4-7 of WCAP 10105 for 6-inch Schedule 160 piping for an internal pressure of 5000 psi is 516 in-kips. The moments for the sum of deadweight and water slug discharge for the components listed in Table 6-16 of the Unit No. 1 submittal at nodes 690, 700 and 700, respectively, are 133.6, 158.3 and 158.3 in-kips. The moments for Unit No. 2 at nodes 1070, 1030 and 1030, respectively, are 130.6, 134.2 and 134.2 in-kips.