ATTACHMENT 1

SURRY POWER STATION UNITS 1 AND 2
PROPOSED TECHNICAL SPECIFICATION CHANGE

b. Three valves shall be operable when the reactor coolant average temperature is greater than 350°F, the reactor is critical, or the Reactor Coolant System is not connected to the Residual Heat Removal System.

c. Valve lift settings shall be maintained at 2485 psig $^{+1}_{-1}$ percent.*

4. Reactor Coolant Loops

Loop stop valves shall not be closed in more than one loop unless the Reactor Coolant System is connected to the Residual Heat Removal System and the Residual Heat Removal System is operable.

5. Pressurizer

a. The reactor shall be maintained subcritical by at least 1% until the steam bubble is established and the necessary sprays and at least 125 KW of heaters are operable.

b. With the pressurizer inoperable due to inoperable pressurizer heaters, restore the inoperable heaters within 72 hours or be in at least hot shutdown within 6 hours and the reactor coolant system temperature and pressure less than 350°F and 450 psig, respectively, within the following 12 hours.

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* For the remainder of Cycle 10 operation for both units the valve lift settings shall be maintained at 2485 psig $^{+5}_{-1}$ percent.

ATTACHMENT 2

SURRY POWER STATION UNITS 1 AND 2
DISCUSSION OF PROPOSED CHANGE
AND
SIGNIFICANT HAZARDS CONSIDERATION

DISCUSSION OF PROPOSED CHANGES

Recent industry test data accumulated by Westinghouse indicates that the pressure at which a pressurizer safety valve (PSV) will lift may change by more than the allowable setpoint tolerance defined in the Technical Specifications when the valve is tested and set at conditions different than the as-installed conditions. Testing of several Crosby 6M6 forged body and cast body pressurizer safety valves from various plants was performed by Westinghouse using a loop seal configuration with 300°F water in the loop. The loop seal was then drained and the set pressure was checked with steam. The valve set pressure was observed to drop approximately 4% to 8% for these valves. It was concluded that other plants which set their safety valves on steam and install them on hot or cold water loop seals may also have set pressures higher than the 2485 psig ±1% limiting condition for operation set forth in the current Technical Specifications.

On October 13, 1989, Surry Unit 2 was shut down so that leakage from the "B" pressurizer safety valve could be corrected. While the unit was shut down, the potential unreviewed safety question described above was identified. At that time, we considered the most prudent course of action to be shipping the three Unit 2 safety valves to the Westinghouse Western Service Center so they might be (a) tested at as-found conditions with steam, (b) tested at as-found conditions in a loop seal configuration, and (c) adjusted to the proper setpoint and tolerance for a loop seal configuration. The data from the Unit 2 valve tests have also provided information which can be correlated to the expected condition of the Unit 1 valves. The measured Unit 2 safety valves' setpoint change from steam to water loop seal conditions ranged from +3.5% to +5.0%.

Because the Unit 1 pressurizer safety valves were tested and had their setpoints established using saturated steam in a manner similar to that previously used for the Unit 2 safety valves, an evaluation of the impact of potentially deviated PSV lift setpoints on the UFSAR transients has been performed. The transients which are most severely affected by the inoperability of the pressurizer safety valves were reanalyzed. The results of the transient analysis evaluations and reanalyses have shown that the peak reactor coolant system (RCS) pressure remains below the 110%

design overpressure limit for pressurizer safety valve lift setpoint changes of up to +5.4% above the nominal lift setpoint of 2485 psig.

In their formal notification of this issue, Westinghouse provided the results of a generic sensitivity study which indicated the impact of increased PSV set pressures on each of the following transients: Loss of Load/Turbine Trip, Main Feedline Break, Locked Rotor, and Rod Ejection. Their study showed that the transient pressure in each of these transients remains below 120% of design pressure (the faulted condition stress limit).

In the study performed for Surry, the Loss of Load/Turbine Trip, Locked Rotor, Main Feedline Break, RCCA Ejection, and Loss of Normal Feedwater transients were evaluated. The results of this study are summarized in the following.

EVALUATION OF UFSAR TRANSIENTS

We have evaluated the UFSAR transients and determined that the Loss of Load/Turbine Trip, Locked Rotor, Main Feedline Break, RCCA Ejection, and the Loss of Normal Feedwater transients are potentially affected by a deviation in the PSV lift setpoint. The Loss of Load/Turbine Trip and the Locked Rotor were reanalyzed and the remaining transients reevaluated to determine a maximum increase in the PSV lift setpoint that would maintain the peak RCS pressures below the ANS Condition II licensing basis overpressure safety limit of 2750 psia (110% of design pressure). The conditions assumed in the reanalyses are equivalent to, or are conservative with respect to, the conditions of the current licensing analysis unless otherwise noted.

LOSS OF LOAD/TURBINE TRIP

For the case of the Loss of Load/Turbine Trip in which the PSV lift setpoint was increased +5.4%, the maximum reactor coolant system (RCS) pressure remained below 110% of design pressure.

LOCKED ROTOR

For the Locked Rotor transient, the PSV's can be assumed to be inoperable, and the peak RCS pressure remains below 110% of the design pressure. The assumed inoperability of the PSV's provides only a minimal impact on the RCS overpressure results of the current licensing analysis.

MAIN FEEDLINE BREAK

The Main Feedline Break (MFLB) transient is not a part of the formal licensing basis for Surry. However, the MFLB transient was analyzed to permit comparison of the thermal/hydraulic conditions at the PSV inlets to conditions employed in valve tests conducted by EPRI. It was concluded that the pressurizer safety valves can be expected to perform adequately under MFLB conditions, even with a deviation in PSV lift setpoint pressure as high as +10%, since the thermal hydraulic conditions that would be experienced in the applicable MFLB scenario with these PSV lift setpoints are within the EPRI test conditions.

LOSS OF NORMAL FEEDWATER

The evaluation of the Loss of Normal Feedwater (LONF) transient concluded that a +10% deviation in the PSV lift setpoint would result in a peak RCS pressure during a LONF of less than or equal to 2750 psia. If either a single PORV or the high pressurizer pressure reactor trip is actuated, the maximum pressure attained in this transient is not high enough to challenge the nominal PSV lift setpoints. Because the high pressurizer pressure reactor trip is a safety-grade reactor trip, it may be concluded that the peak pressure in a LONF transient will remain below the nominal PSV lift setpoint of 2500 psia.

ROD EJECTION

The evaluation of the Rod Ejection transient concluded that the peak pressure attained during this transient will remain well below the nominal PSV setpoint of 2500 psia. A high PSV setpoint, or even inoperable PSV's, will not impact the results of the Rod Ejection transient analysis.

UNIT 2 'C' PSV LIFT

During the recent Unit 2 plant heatup, while performing the 100 psi overpressure test of the RCS per Technical Specification 4.3, the 'C' pressurizer safety valve lifted at approximately 2335 psig due to an apparent loss of loop seal and consequential valve setpoint shift down in pressure. Based on the 'C' valve "as-left" setting of approximately 2480 psig, a downward shift of 5%, as anticipated from previous Unit 2 valve testing, would leave the valve setpoint at approximately 2356 psig. Accordingly, 'C' valve lifting due to a loss of loop seal during the overpressure test is not inconsistent with the Unit 2 valve test results. First, RCS pressure control instrumentation accuracy is approximately ±2.5 percent. This accuracy represents approximately 1 percent of valve setpoint. Second, the nature of the overpressure test results in conditions which are different than the conditions for valve lift setpoint testing. Specifically, during the overpressure test, pressure is increased gradually and then the pressure is held for an extended time as opposed to the transient nature of valve setpoint testing. During the period of time that the 'C' valve was subject to 2335 psig, it is suspected that the loop seal was lost and that minor leakage of a mixture of water and steam (characterized as "simmering") continued past the valve seat and aggravated the leakage condition by uneven heating of the dissimilar materials of the valve seat and body. This condition is postulated to result in an earlier lifting than if the valve is subject to a rapid pressure transient of an equivalent magnitude. We conclude that the Unit 2 'C' valve lift is technically consistent with the previous valve testing results for setpoint shift assuming a loss of the loop seal and considering the specific conditions of the overpressure test.

CONCLUSIONS

It may be concluded from the results of the UFSAR transient evaluations and reanalyses that the maximum overpressure attained in any UFSAR transient will remain below 2750 psia (110% of design pressure) provided the PSV lift setpoints remain below 2635 psia (105.4% of the design lift setpoint). The actual drift of the setpoint from the nominal value of 2485 psig appears to be inversely related to the temperatures which the safety valves are exposed to during testing and in operation. The Unit 1 safety valves were set and tested using saturated steam but are installed with a water loop seal configuration with the water temperature in the area of the valve inlet flange of approximately 300°F. Unit 2 valves are presently being reset, tested and installed in the same manner.

The consequence of a loss of the water loop seal has been reviewed for the PSVs in both units and it has been determined not to be of concern with regard to the setpoint drift issue. The loss of the loop seal would expose the safety valves to conditions which would approach those under which the valves were initially set.

The loop seal drains are being cut and capped to eliminate a potential leakage path. Additionally, there is a RTD and an acoustic monitor in each safety valve discharge line which is used to monitor safety valve status. Each RTD is located approximately one foot from the outlet flange of the safety valve. Finally, we are evaluating the installation of additional temperature monitoring equipment to further assist in determining the condition of the loop seal.

PROPOSED TECHNICAL SPECIFICATION

Based on the test results for the Unit 2 PSV lift setpoints, the Unit 1 and 2 PSV lift setpoints can be expected to be outside the currently allowable ±1% of the nominal setpoint specified in LCO 3.1.A.3.c. The analyses and evaluations discussed above have shown that the design licensing basis ANS Condition II overpressure safety limit can be met for setpoint increases of up to 5.4% over the nominal setpoint of 2485 psig. Accordingly, we propose, on an interim basis, a change to Technical Specification 3.1.A.3.c to change the allowable PSV setpoint tolerance to +5%, -1% of the nominal setpoint and to delete the existing footnote to avoid misinterpretation of the method being presently employed to set the valves. This change would remain in effect for the remainder of Units 1 and 2 Cycle 10 operation.

This requested interim change of PSV setpoint tolerance to +5%, -1% ensures that the RCS transient pressures analyzed in any of the accidents discussed in the UFSAR would remain within the licensing basis acceptance criteria. Additionally, the proposed change permits valve lift settings which minimize the potential for challenges of safety valves due to a loss of a loop seal. Based on the Unit 2 PSV test results, there is reasonable assurance that the PSV's for both units will not exceed the +5% tolerance.

The ASME Code requirements for the pressurizer safety valves have been reviewed with respect to acceptable setpoint tolerances. The Code of record for the Surry Unit 1 and 2 pressurizer and its associated safety valves is ASME Section III - 1965. This Code provides no specific requirements for the setpoint tolerances for the safety valves. Surry is committed to meet the requirements of ASME Section XI - 1980 with Winter of 1980 Addenda. Therefore, this code was reviewed as well. Once again, no criteria are established in this code for safety valve setpoint tolerance. The setpoint tolerance is therefore governed only by the Technical Specification and the analyses which provide the basis for the Technical Specification.

10CFR50.90 SIGNIFICANT HAZARDS CONSIDERATION

Virginia Electric and Power Company has reviewed the proposed changes against the criteria of 10 CFR 50.92 and has concluded that the changes as proposed do not pose a significant hazards consideration. Thus, operation of the Surry Power Station in accordance with the proposed changes will not:

1. Involve a significant increase in the probability of occurrence or consequences of any accident or malfunction of equipment which is important to safety and which has been evaluated in the UFSAR. The proposed change effectively recognizes the potential shift in lift setpoint due to testing methodology. As such, the setpoint shift being positive, the probability of a safety valve challenge may be reduced. The consequences of such a challenge are unaffected as the UFSAR analysis remains bounding within the proposed setpoint tolerance. In addition, the Units 1 and 2 valve setpoint shift is expected to be in the same range as the Unit 2 valve test results (+3.5% to +5%) and therefore no increase in the consequences of any accident or malfunction of equipment which is important to safety is expected.

2. Create the possibility of a new or different type of accident from those previously evaluated in the safety analysis report. No modifications are being made to the pressurizer safety valves for either unit at this time. Potential installation of temporary strap-on temperature instrumentation has no operational impact on valve performance. Capping of loop seal drains is being performed only to ensure that the loop seals are not lost due to leakage through the drains and hence has no impact on the intended design of the safety valves. With the setpoint change expected to be in the same range as the Unit 2 valve test results, there is no new or different kind of accidents or accident precursors expected. The additional measures being implemented are only being used to further ensure that the system pressure will remain below 2750 psig (110% of design pressure) during any analyzed transient or operating condition.

3. Involve a significant reduction in the margin of safety. Plant operations are not being changed. Although accident analysis assumptions have been modified to assume an initial 5.4% shift in pressurizer safety valve lift pressure, there is no reduction in the margin of safety since the 110% design pressure is not exceeded in any UFSAR evaluated accident. For valve setpoint tolerance consistent with setpoint shift experienced during testing, the accident analysis remains bounding.

ATTACHMENT 3

SURRY POWER STATION UNIT 1
JUSTIFICATION FOR EMERGENCY TECHNICAL
SPECIFICATION CHANGE REQUEST

Justification For Emergency Technical Specification Change Request

10 CFR 50.91 requires an explanation for requests of emergency, including why such action cannot be avoided. This discussion provides justification for the emergency processing of the proposed technical specification on pressurizer safety valve lift setpoint tolerance.

Background

During early October 1989, while addressing a pressurizer safety valve leakage concern on Unit 2, Virginia Electric and Power Company became aware of an internal Westinghouse concern on the potential for valve lift setpoint shift on Crosby valves due to safety valve test methodology. Formal notification of this concern by Westinghouse was transmitted by letter dated October 16, 1989. Based on this potential concern, three Unit 2 pressurizer safety valves were tested for setpoint calibration while the unit was shutdown to repair the one leaking valve. Setpoint shifts of +3.5 to +5.0% were observed in the Unit 2 valve testing.

Based on Unit 2 test results, Unit 1 was conservatively assumed to be also affected and discretionary enforcement was sought and granted on October 19, 1989, for continued operation of Unit 1. This discretionary enforcement was confirmed by our letter Serial No. 89-750 dated October 23, 1989, and your letter of October 27, 1989. The discretionary enforcement was for a six-week period ending December 1, 1989, and was predicated on working with the NRC staff and Westinghouse Owners Group (WOG) to reach a generic resolution to the issue rather than individually resolving this concern on each docket. On October 27, 1989, the NRC staff met with the WOG on this issue. No immediate generic solutions appear imminent on this issue based on that meeting and subsequent discussions with your staff.

After testing, the Unit 2 pressurizer safety valves were reset using a water loop seal and reinstalled in Unit 2. During this time, the potential for premature valve lifting of operating pressures was considered in discussions with the NRC and other utilities. At the time, we considered that adequate margin would exist and that both this new concern as well as the initial generic setpoint shift issue could be addressed by our corrective actions on Unit 2. However, on November 6, 1989, during pressure testing in accordance with Technical Specification 4.3 to determine RCS leakage prior to returning Unit 2 to service, 'C' safety valve lifted due to an apparent loss of loop seal and consequential setpoint shift down in pressure. We have concluded that resetting the pressurizer safety valve using the water methodology is premature given the present uncertainties in valve operation and loop seal interaction. Since we have established that our safety analysis remains bounding for valves set using the steam methodology and to minimize the potential for challenges of pressurizer safety valves, we have decided to reset these valves using the steam methodology pending generic resolution of the problem. This work is presently underway.

Discussion

Based on the unlikelihood of generic resolution during the period of discretionary enforcement for Unit 1 or in time to support Unit 2 restart, we have proposed an emergency Technical Specification change to address relief through the remainder of the cycle for both units. The NRC has not appeared to be adverse to granting relief on this issue. Rather, the issue has been to identify the appropriate administrative vehicle for granting relief pending generic resolution. Clearly, the six-week period of discretionary enforcement for Unit 1 was not intended to support resolution of this issue by normal, individual processing of a Technical Specification changes on multiple dockets. Although this issue appears generic in nature, we are constrained to act individually; and, within the time frame of Unit 1 discretionary enforcement or Unit 2 restart , we must request emergency processing of the proposed Technical Specification change.

Impact

Without emergency processing of the proposed Technical Specification change, Unit 1 will have to be shutdown at the end of the discretionary enforcement period and Unit 2 will be unable to restart due to violation of TS 3.1.A.3.c. Discretionary enforcement for Unit 1 ends on December 1, 1989. Other than resolution of this issue, Unit 2 is presently scheduled for restart on November 23, 1989.

Conclusion

As we have established in Attachment 2, the proposed setpoint tolerance change is within the limitations of the existing safety analysis and no significant hazard consideration is generated due to the change. We have promptly addressed this issue by testing and setting Unit 2 valves based on best available information, evaluating Unit 1 safety impact, and resetting Unit 2 valves based on current circumstances, participating in generic resolution efforts, and now seeking regulatory resolution on Unit 1 and 2 of what appears to be a generic concern. Based on the short amount of time remaining on the Unit 1 discretionary enforcement the imminent restart of Unit 2, the unlikelihood of generic resolution during the remaining time, and our good faith effort to address this issue, we request emergency processing of the proposed interim Technical Specification change on Units 1 and 2.