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NUCLEAR REGULATORY COMMISSION
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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO THE FLAW EVALUATION OF THE CORE SPRAY INTERNAL PIPING

VERMONT YANKEE NUCLEAR POWER CORPORATION

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1.0 INTRODUCTION

During the current Vermont Yankee refueling outage which began September 6, 1996, crack-like indications were identified at two locations in the core spray (CS) internal downcomer piping. The internal CS piping is a 5-inch diameter, schedule 40 pipe composed of Type 304 stainless steel material. The two flawed locations are both on the collar-to-shroud weld (1P8b and 3P8b). This weld is not associated with the piping pressure boundary but rather is a separate sleeve that attaches the CS piping to the shroud and prevents leakage from the inside to the outside of the core shroud at the location where the CS piping enters the shroud. The flaws were found using an automated ultrasonic testing (UT) system available on a remote-operated vehicle that was being used for the first time at Vermont Yankee. For weld 3P8b, six separate cracks were identified. The total length of these indications as measured by UT were 14.52" (260°). The length of the indication in weld 1P8b was 1.1". No other indications on the CS piping or sparger were identified.

By letter dated October 9, 1996, the licensee submitted to the NRC its flaw evaluation of the CS internal piping. The results of the licensee's evaluations concluded that the structural integrity of the CS piping collar will be maintained and the indications are acceptable for continued operation during the next fuel cycle without repair. The staff's evaluation and conclusions are provided below.

2.0 EVALUATION

2.1 Scope of Inspection

By letter dated September 25, 1996, the licensee provided the NRC staff with its plans for performing CS system inspections during its 1996 refueling outage. The licensee informed the staff of its intention to modify its present commitments associated with IE Bulletin (IEB) 80-13, "Cracking in Core Spray Spargers," dated May 12, 1980, during its current refueling outage at the Vermont Yankee plant. Specifically, the licensee stated that they planned to modify the scope and examination techniques that they had previously used to perform inspections of the CS internal piping. This modification would follow the industry guidance contained in the Boiling-Water Reactor Vessel and Internals Project (BWRVIP) document, "Core Spray Internals Inspection and Flaw Evaluation Guidelines (BWRVIP-18)," dated July 26, 1996. The scope and

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examination techniques previously used for the CS spargers would not change and would follow the guidelines in IEB 80-13. Using the BWRVIP-18 guidance for the inspection and scope of the CS internal downcomer piping, a baseline inspection of all welds would be performed using UT for Vermont Yankee. For those welds that would not be accessible using UT, the licensee would follow the BWRVIP-18 guidance for enhanced visual examination (EVT-1) which is capable of achieving a resolution of 0.0005 inches (0.0127 mm). Because the inspection methods proposed by the licensee would focus on areas of the CS piping which are more likely to experience intergranular-stress corrosion cracking (IGSCC) and the proposed inspection methods for the CS internal downcomer piping are more stringent than those recommended in IEB 80-13, the staff finds that the scope and inspection methods used for the inspection of the CS internal piping at the Vermont Yankee plant are acceptable for this outage. It should be noted that the NRC staff is presently reviewing the acceptability of using BWRVIP-18 generically for all BWRs. While the staff has not identified any major deficiencies in the BWRVIP's technical assessment at this time, neither has the staff made a determination as to its generic acceptability. Therefore, the licensee should be aware that if concerns are identified during the staff's generic review of BWRVIP-18, and if the licensee intends to follow the BWRVIP-18 guidance in the future, the NRC staff may request that the licensee also address these concerns on a plant-specific basis.

As a result of using the BWRVIP-18 inspection guidance for the piping in the annular area, the licensee was able to perform UT examination of all welds in the downcomer piping except for five welds that were inaccessible to the UT system. Four of the welds were located at the lower end of the pipe elbow near the pipe collar (P4d). The other inaccessible weld was the collar-to-shroud weld, 2P8b. For these welds, an enhanced visual examination (EVT-1) was performed[1].

2.2 Flaw Evaluation

The results of the inspections of the CS piping welds indicate that the two identified cracks in the collar-to-shroud welds (1P8b and 3P8b) are of IGSCC origin. Because IGSCC is known to be initiated from the inside piping surface, visual examination can only find flaws that are through wall. Therefore, the licensee's UT examination of the flaws provides reasonable assurance that the flaws have been adequately detected and sized. Because the flaws are located where the collar is welded to the shroud wall, it was inconclusive whether the flaws were on the shroud side or the collar side.

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[1] A weld that is inaccessible to visual and UT examination is weld P9. This weld is one of four typical welds and is located under the collar in the CS piping just before it enters the shroud. This weld is shop-fabricated and ground flush on the inside. Because of the additional controls imposed on this shop-fabricated weld, the lack of crevices for cracking to initiate, and the small loads imposed on this weld, it is not likely that IGSCC will occur in this weld.

The licensee was not able to detect the flaw using visual inspection (EVT-1) of the 3P8b weld. The licensee, therefore, conservatively assumed the flaws to be through-wall.

In its crack growth calculation, the licensee used a bounding crack growth rate of 5.0×10^{-5} in/hr as recommended by the BWRVIP in the document, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines," dated June 1996 (GE Report No. GE-NE-B13-01805-21). The licensee stated that the crack growth rate is conservative because the reactor water conductivity at the Vermont Yankee plant has been better that the BWR fleet average. The coolant conductivity at Vermont Yankee has averaged 0.11 μS/cm over the last three cycles compared to a conductivity of approximately 0.3 μS/cm during the first five cycles of operation. The staff finds that the bounding value used by the licensee for its crack growth rate is, therefore, acceptable.

By using the bounding crack growth rate, the licensee calculated the remaining ligament for weld 3P8b at the end of the next fuel cycle of 18 months to be 0.61 inch. With this calculated remaining ligament, this weld would not have a moment load carrying capability. The licensee assumed the remaining ligament to act like a hinge and evaluated the capability of the weld to support only axial loads (i.e., the moment capacity of the weld and piping at that location were released in the piping analytical model). Evaluated in this manner, the weld would possess a safety factor of 5.8 for axial loads compared to the required safety factor of 1.4 for the emergency/faulted plant condition. However, because the calculations did not clearly demonstrate that the remaining ligament would be able to withstand the moments induced by required load combinations, the staff finds that the structural integrity of weld 3P8b is not assured for the next fuel cycle. However, even without this weld intact, the licensee's analysis showed that the CS piping system would remain functional. The staff's evaluation of the licensee's piping analysis model and results are discussed in the following section of this evaluation.

For weld 1P8b, the crack length was determined to be 1.1" in length. To evaluate the acceptability of this flaw, the licensee had prepared a flaw evaluation handbook that provided a set of allowable flaw lengths at various CS piping locations and leak rate calculations for postulated through-wall indications. The method used in the analysis was based on a finite-element analysis of the CS piping and sparger using the ANSYS computer program to determine the membrane and bending stresses from the postulated loadings. Applying the stresses at several key locations in the piping system, the licensee used limit load methods of paragraph IWB-3640 of the ASME Boiler and Pressure Vessel Code, Section XI as a guide to determine the allowable flaw lengths. Lastly, the licensee performed leak rate evaluations corresponding to the allowable flaw sizes at the end of cycle. The licensee's flaw evaluation handbook showed that the total allowable effective crack with one cycle of crack growth would be 10.04 inches. Similarly, the licensee calculated the acceptable leak rate value to be 11.9 gpm. However, because the crack in the collar-to-shroud weld is not through the piping pressure boundary, no leakage is expected. Therefore, the crack length of 1.1" for

weld 1P8b and the leak rate are within the allowable flaw length and leak rate acceptance criteria, respectively, and are, thus, acceptable for one operational cycle.

2.3 Core Spray Piping Analysis

The CS piping structural analysis was performed to demonstrate that, with a completely severed P8b weld at the shroud/collar interface, the maximum stresses in the piping during normal operation and under design basis accident conditions will remain within ASME Code, Section III allowable stress limits. A finite-element model consisting of one loop of the internal CS piping was developed to analytically determine the structural integrity of piping under operational and design basis loadings.

The geometry of the internal CS line and sparger in the analytical model was based on as-built drawings listed in Reference 1. The licensee analyzed the piping system for deadweight and seismic inertial loadings. Other applied loads on the CS line included anchor displacements, fluid drag and CS flow initiation loadings.

2.3.1 Evaluation of the Loadings

The inertial loadings were due to seismic and flow-induced vibration of the CS line including interaction with the reactor pressure vessel (RPV) and the core shroud. Seismic excitation which may cause anchor displacements, is imparted to the CS lines at the vessel nozzle, the support brackets and the attachment points to the shroud. Anchor displacements of 0.15 inches and 0.177 inches for the operating basis earthquake (OBE) and the safe shutdown earthquake (SSE) respectively, were obtained from previous analyses (Reference 2), which have been approved by the staff.

The drag loads are due to the fluid flow past the CS lines. The flow in the annulus region during normal operation exerts a downward drag force on the CS piping. The magnitude of this loading was determined based on a conservative value of 5 feet per second for the fluid velocity in the vessel annulus region. During upset conditions, CS operation is assumed with no feedwater flow, therefore, the drag loads are insignificant. Drag loads of up to 283 lbs/ft could occur during a postulated double-ended break of either the recirculation line or the main steam line. The pressure and flow loads, which occur only during CS operation, are based on an internal pressure of 82.2 psi and a flow of 4300 gallons per minute (Reference 3). Water hammer loads are insignificant because the CS inlet valve ramps open over a period of time upon system actuation. Additionally, the piping is full of water during actuation due to the presence of the vent hole on the top of the T-box.

The two anchor points of the internal CS line at the RPV and shroud attachment locations expand vertically and horizontally at different rates primarily due to differences in the thermal expansion properties of the RPV low alloy steel and the shroud stainless steel. But there are a number of other factors which affect differential anchor point motion. These include RPV thermal and pressure cycles during various transients and the interval between the loss-of-coolant accident (LOCA) event and the CS initiation. The

resultant stresses due to differential anchor motion were treated as secondary stresses in the analysis. Appropriate bounding anchor displacements during normal operation, loss of feedwater pump transient, and during LOCA conditions were considered in the analysis. The information relative to the RPV thermal cycles was derived from data for a similar plant (Reference 4) since the Vermont Yankee RPV specifications did not contain this information in sufficient detail. The anchor displacement values used in the faulted condition analysis included the shroud vertical displacement during the combined SSE plus steam line break event.

The staff reviewed the design input loads for the CS piping stress analysis as discussed above and finds that appropriate loadings and load combinations have been considered in the piping analysis. The staff finds the design input loads are, thus, acceptable.

2.3.2 Evaluation of the CS Piping Stress Analysis

The licensee evaluated the CS piping with various postulated degraded conditions of the P8b collar welds using a finite-element analytical model. Three analysis cases were selected to envelop all possible postulated failure modes of the collar. These bounding cases were as follows: (1) the collar weld was assumed intact and capable of withstanding moment and translational loads, (2) the collar weld was assumed partially intact and capable of withstanding translational loads only, and (3) the collar weld was assumed completely cracked, in which case the CS annulus piping is capable of displacing up to 1/4-inch axially and up to 0.028 inches vertically and horizontally. These displacements were limited by clearances between the CS piping, sparger and core shroud.

In the first case, neither displacement nor rotation was allowed along the three axes at the P8b weld location in the analytical model. In the second case, no displacement was allowed, but the pipe was free to rotate along the three axes at this location. In the third case, where the weld was assumed completely cracked, displacement was specified along the three axes and rotation was allowed in all directions. For all the degraded weld cases analyzed, the stresses in the CS system annulus piping were determined to be within ASME Code, Section III allowable stress limits.

The licensee also evaluated the flow induced vibration (FIV) effects of the CS piping. Assuming the collar weld were completely severed, the licensee evaluated the likelihood of rattling in the piping section near the collar due to flow induced forces during normal plant operation. The resulting moments from displacements of 0.25 inch in the radial direction and 0.028 inches in the horizontal and vertical directions were combined by the absolute sum method, and the peak stress range at each of the welds was calculated at the fillet and groove welds respectively. The maximum value of the calculated alternating stress (one-half of the peak stress range) was determined to be 1398 psi. This value is considerably less than the endurance limit of 10,000 psi, indicating that even if the collar weld were completely severed and the CS pipe could move to the extent permitted by the clearances, it would not pose fatigue concerns due to flow-induced vibration. The fundamental frequency of the degraded CS piping was determined to be 23.4 Hertz as

compared to 24.6 Hertz for the original piping with the weld intact. This slight shift in the frequency was judged to be insignificant for FIV considerations.

A primary plus secondary stress evaluation showed that when the FIV stresses were added to the other accident condition stresses, the largest stress range was still less than the ASME Code allowable value of $3S_m$ which indicates that sufficient margin exists.

Based on its review of the licensee's structural analysis of the degraded CS piping including loads development, analytical methodology, boundary conditions and evaluation of flow-induced vibration effects, the staff concludes that the licensee has demonstrated that the CS piping system will maintain its functional capability during the next fuel cycle without repairs.

3.0 CONCLUSION

Based on the staff's review of the licensee's flaw evaluations, the staff concludes that the structural integrity of collar-to-shroud weld (1P8b) will be maintained during the next fuel cycle on the basis that the final flaw size at the end of the next fuel cycle will not exceed the Code allowable value. For collar-to-shroud weld (3P8b), the staff concludes that the CS internal piping will be able to maintain its functionality even if it assumed that the subject collar-to-shroud weld loses its structural integrity. Therefore, Vermont Yankee can be operated for the next fuel cycle without repairing the subject collar-to-shroud welds (1P8b and 3P8b). However, continued plant operation beyond the next fuel cycle will depend on the satisfactory evaluation on the reinspection results or by implementing acceptable repairs during the next refueling outage.

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REFERENCES

1. Vermont Yankee Drawings:
   (a) Shroud Drawing No. 5920-528
   (b) Core Spray Line Drawing No. 5920-1806
   (c) Vessel Drawing No. 5920-103
   (d) Reactor Assembly Drawing Nos. 5920-3773 and -3774
   (e) Core Spray Sparger Drawing No. 5920-3776.

2. MPR Calculation No. 249-9502-728 Rev.1 related to the Vermont Yankee Core Shroud Repair.

3. "Vermont Yankee Nuclear Power Station-Primary Structure Seismic Analysis for Core Shroud Evaluation" GE Report No. GE-NE-523-A194-1294, Rev. 0, DRF No. B13-01750, December 1994.

4. "Reactor Thermal Cycles" GE Drawing No. 761E708.