Tennessee Valley Authority, Post Office Box 2000, Soddy-Daisy, Tennessee 37384-2000

August 31, 2001

10 CFR 50.55a

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Gentlemen:

In the Matter of	)	Docket Nos. 50-327
Tennessee Valley Authority	)	50-328

SEQUOYAH NUCLEAR PLANT (SQN) - RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION (RAI) REGARDING RISK-INFORMED INSERVICE INSPECTION (RI-ISI) PROGRAM

Reference: NRC letter to TVA dated July 13, 2001, 2001, "Sequoyah Nuclear Plant, Units 1 and 2 - Request for Additional Information on a Proposed Risk-Informed Inservice Inspection Program (TAC Nos. MB1566 and MB1567)"

This letter provides the additional information you requested by the reference letter to support NRC review of SQN's RI-ISI Program. The enclosure provides TVA responses to the NRC staff questions.

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We appreciate NRC's diligence in reviewing our request within the schedule to support the start of SQN's upcoming Unit 1 Cycle 11 refueling outage (October 22, 2001). Should you require additional information or clarification, please contact us as soon as possible.

No commitments are made in this response. Please direct questions concerning this issue to me at (423) 843-7170 or J. D. Smith at (423) 843-6672.

Sincerely,

Pedro Salas
Licensing and Industry Affairs Manager

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ENCLOSURE 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING SEQUOYAH (SQN) RISK INFORMED INSERVICE INSPECTION (RI-ISI) PROGRAM

NRC Question 1:

One major step in the Westinghouse Commercial Atomic Power (WCAP) process is the identification of degradation mechanisms and the development of corresponding pipe failure frequencies. The requested Table 1 summarizes the qualitative results of this step by identifying the different degradation mechanisms, combinations of mechanisms, and the prevalence of the different mechanism. The calculated ranges in Table 1 summarize the quantitative results of the analysis. This information will illustrate how the degradation mechanism identification and failure frequency development step in the WCAP methodology was implemented, and provided an overview of the results generated. Please expand the current Table 3.4-1 to include the following information.

a) System	b) Degradation Mechanism/ Combination	c) Failure Probability Range at 40 years with no ISI		d) Number of Susceptible Segments	e) Comments
		Leak	Disabling Leak		

a) System: Each system included in the analysis.

b) Degradation Mechanism/Combination: Segment failure probabilities are characterized in the WCAP method by imposing all degradation mechanisms in a segment (even if they occur at different welds) and the worst case operating conditions at the segment on a representative weld, and using the resulting failure probability for the segment. Please identify the dominant degradation mechanisms and combination of degradation mechanisms selected in each system. The reported mechanisms should cover all segments in the system. The table in the current submittal is not clear about which specific degradation mechanisms or combination of mechanisms are included in the leak estimates provided.

NRC Question 1 (continued)

c) Failure Probability Range at 40 years with no inservice inspection (ISI): For each dominant degradation mechanism and combination of degradation mechanisms, please provide the range of estimates developed for the leak and disabling leak sizes as applicable. The table in the current template provided the range of leak estimates only.

d) Number of Susceptible Segments: Please identify the total number of segments susceptible to each dominant degradation mechanism and combination of degradation mechanisms.

e) Comments: The contents of this column are still being developed. It should provide further explanation and clarifications on the degradation mechanism and results as appropriate. Examples of items to be included are identification of which degradation mechanism are applied to socket welds and if a break calculation was needed to evaluate pipe whip constraints.

TVA Response:

Tables 1 and 2 provide a summary of the requested information in the format agreed to with the Westinghouse Owners Group (WOG) in the revised RI-ISI template as Table 3.4-1.

Note: A teleconference between NRC staff and WOG on July 18, 2001 resulted in agreement regarding information provided in response to NRC Question 1, items d and e.

Table 1
Failure Probability Estimates (without ISI) for Sequoyah Unit 1

System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
AF	• Thermal Fatigue & Water Hammer • Thermal Fatigue & Steam Hammer • Thermal Fatigue, Water Hammer & Striping / Stratification	2.1E-05 1.0E-04 6.8E-04	1.6E-05 - 3.4E-04 6.1E-04 1.8E-04	• Striping/stratification could occur at low-flow conditions near the interface with main feedwater. • In AFW (piping upstream of check valve isolating FW from AFW) check valve leakage could cause thermal striping or stratification. • Water hammer in the FW line could occur from a plant trip. AFW piping connected to the FW line could be affected by the water hammer loading. • Steam hammer could occur in the Main Steam piping. The piping for the turbine driven AFW pumps connected to the Main Steam line could be affected by the steam hammer loading.

BD	• Thermal Fatigue, Steam Hammer & Vibratory Fatigue • Thermal Fatigue, Steam Hammer, and FAC • Thermal Fatigue, Steam Hammer, Vibratory Fatigue, & FAC	1.7E-03 5.6E-01 5.6E-01	4.6E-03 5.6E-01 5.6E-01	• An augmented program for FAC exists for BD piping. • Steam hammer loadings are considered on the BD piping to account for the loading from a steam generator blowdown. • Vibrational loading is considered on the piping connected to the steam generator.
CH	• Thermal Fatigue • Thermal Fatigue & Vibratory Fatigue • Thermal Fatigue, Vibratory Fatigue, & Water Hammer • Thermal Fatigue, Vibratory Fatigue, & Striping / Stratification	3.5E-06 - 6.7E-04 6.4E-06 – 8.4E-03 1.2E-05 – 8.7E-03 7.0E-05 – 6.1E-04	• SLOCA 1.6E-04 • IE/SYS 4.9E-06 - 2.8E-04 • SLOCA 5.5E-03 • IE/SYS 4.3E-06 – 5.5E-03 1.4E-05 – 5.6E-03 • MLOCA 6.1E-05 – 2.2E-04 • SLOCA 5.6E-05 – 2.7E-04 • IE/SYS 2.8E-05 – 4.0E-04	• The configuration of the charging path to the selected RCS cold leg was identified as potentially susceptible to thermal cycling/fatigue failure when stagnant (NRC Bulletin 88-08). The potential for this has been minimized by maintaining flow through the line. • Flashing and cavitation occurs at the letdown orifices which could produce vibratory loadings on the adjacent piping . • Vibratory loadings were considered on the piping connected to the centrifugal charging pumps and the piping connected to the RCL. • Potential for transient loads exists at the discharge of the high capacity pumps and at the discharge relief valves.
CI	• Thermal Fatigue • Thermal Fatigue & Erosion / Corrosion	1.1E-06 – 8.4E-04 6.2E-02	2.2E-07 – 4.8E-04 6.2E-02	• Material wastage was considered for the carbon steel ERCW and Fire Protection piping.

CS	• Thermal Fatigue • Thermal Fatigue & Water Hammer • Thermal Fatigue & Vibratory Fatigue • Thermal Fatigue, Vibratory Fatigue & Water Hammer	9.8E-05 – 2.0E-04 7.0E-06 – 2.0E-04 2.0E-05 –2.0E-04 2.0E-05 – 2.0E-04	6.1E-05 – 1.1E-04 3.5E-06 –2.0E-04 7.2E-06 – 1.2E-04 3.3E-05 – 2.0E-04	• The potential for vibration was considered for the piping adjacent to the CS pumps and the piping adjacent to the throttling orifice. • The potential for water hammer due to gas pockets forming in the pump discharge piping was considered. • The potential for water hammer in the spray header piping was considered.
FW	• Thermal Fatigue, Vibratory Fatigue & Water Hammer • Erosion/Corrosion, Thermal Fatigue & Water Hammer • Thermal Fatigue & Water Hammer • Thermal Fatigue & Vibratory Fatigue • Erosion / Corrosion, Thermal Fatigue, Vibratory Fatigue, Water Hammer & Striping / Stratification • Erosion / Corrosion, Thermal Fatigue, Water Hammer & Striping / Stratification	3.0E-04 3.5E-02 – 4.4E-02 8.8E-08 – 4.6E-04 1.9E-04 4.7E-02 4.7E-02	1.1E-03 3.5E-02 – 4.4E-02 1.9E-08 – 5.3E-03 2.1E-04 4.7E-02 4.7E-02	• Vibration was considered for the piping adjacent to the steam generators. • The potential for thermal striping and stratification was considered for the piping between the AFW connection to the FW line and the steam generator. • FAC was considered for the FW normal flow path piping to the steam generators. The locations where high flow velocities cause pipe wall thinning are in the FAC program. • The piping can experience transient loads during a plant trip.
MS	• Thermal Fatigue & Steam Hammer • Thermal Fatigue, Steam Hammer & Vibratory Fatigue	2.7E-07 – 2.1E-04 2.7E-07	1.3E-04 – 9.4E-04 1.3E-04	• The piping can experience transient loads during a plant trip. • Vibration was considered to occur in the piping adjacent to the steam generators.

RC	• Thermal Fatigue • Thermal Fatigue & Vibratory Fatigue • Thermal Fatigue & Striping/Stratification • Thermal Fatigue & Water Hammer	1.4E-09 – 7.9E-05 1.0E-06 – 1.2E-02 6.4E-04 1.8E-07 – 1.2E-05	• MLOCA 1.4E-06 • SLOCA 5.0E-011 – 1.3E-03 • LLOCA 1.7E-06 – 4.2E-06 • MLOCA 9.3E-07 – 6.4E-05 • SLOCA 9.3E-07 – 7.1E-03 • LLOCA 6.6E-04 • MLOCA 6.6E-04 • SLOCA 6.6E-04 • MLOCA 8.1E-05 – 9.2E-05 • SLOCA 8.0E-05 – 1.3E-03	• The RCL piping and the piping connected to the RCL considered vibration. • Thermal striping and stratification occurs in the pressurizer surge line. • Locations where the piping could experience large temperature changes are the pressurizer surge line, tailpipes due to a PORV lifting, and at the Charging nozzles. • Transient loads were considered to occur in the tailpipes due to steam release from pressurizer relief valves.
RH	• Thermal Fatigue • Thermal Fatigue & Vibratory Fatigue • Thermal Fatigue, Vibratory Fatigue & Water Hammer • Thermal Fatigue & Striping / Stratification • Thermal Fatigue & Water Hammer • Thermal Fatigue, Vibratory Fatigue & Striping / Stratification • Thermal Fatigue, Vibratory Fatigue, Water Hammer & Striping / Stratification	4.2E-06 – 1.4E-04 8.5E-06 – 1.9E-04 1.1E-05 – 1.9E-04 1.2E-04 1.1E-05 – 6.7E-04 4.6E-05 1.8E-05	7.6E-06 – 1.8E-04 • SLOCA 2.3E-04 • SYS 3.7E-06 – 7.1E-05 2.6E-05 – 1.5E-04 9.1E-05 2.6E-05 – 2.2E-04 • LLOCA 1.9E-05 • MLOCA 1.6E-05 • SLOCA 1.7E-05 • SYS 1.7E-05 • MLOCA 1.5E-05 • SLOCA 1.5E-05 • SYS 1.6E-05	• System experiences temperature changes from ambient to 350°F when used for shutdown cooling. • Vibration was considered for the piping adjacent to the RHR pumps and for the piping connected to the RCL. • Transient loads were considered in the pump discharge piping due to the potential of gas intrusion in the piping. Venting is performed to remove possible gas intrusion thus reducing the probability of water hammer. • The potential for transient loads was considered on the discharge piping of the relief valves. • NRC Bulletin 88-08 Supplement 3 identified potential thermal stratification / striping concerns for RHR piping connected to the RCL. This concern was evaluated and the SQN RHR piping was determined not to be susceptible to unacceptable thermal stress levels.

SI	• Thermal Fatigue • Thermal Fatigue & Water Hammer • Thermal Fatigue, Water Hammer & Striping / Stratification • Thermal Fatigue, Vibratory Fatigue & Water Hammer • Thermal Fatigue, Vibratory Fatigue, Water Hammer & Striping/ Stratification • Thermal Fatigue, Vibratory Fatigue, Water Hammer, Striping/ Stratification & SCC • Thermal Fatigue & Vibratory Fatigue	3.4E-06 – 7.0E-04 6.6E-07 – 2.3E-04 2.7E-04 – 3.2E-04 1.9E-05 – 9.0E-04 1.8E-05 – 1.0E-02 1.5E-03 – 6.9E-03 2.6E-05 – 1.0E-04	7.4E-07 – 1.7E-04 1.1E-05 – 2.0E-04 1.1E-04 – 1.7E-04 2.1E-05 – 3.4E-04 • LLOCA 2.8E-05 • MLOCA 1.5E-05 – 2.7E-05 • SLOCA 1.5E-05 – 6.4E-03 • SYS 1.6E-05 – 8.7E-03 • MLOCA 3.2E-04 • SLOCA 4.0E-04 • SYS 2.8E-04 – 1.4E-03 1.4E-05 – 7.4E-05	• Vibration was considered for the piping adjacent to the SI pumps and for the piping connected to the RCL. • There is vibration due to cavitation at the 1-1/2" and 2" needle valves. New orifices have been added to reduce vibration due to the cavitation. • NRC Bulletin 88-08 identified potential thermal stratification/striping concerns for piping connected to the RCL. • Transient loads were considered in the SI pump discharge piping due to potential gas pockets. The potential for gas pockets (due to nitrogen coming out of solution) at high points in the piping exists due to back-leakage through check valves. • The potential for transient loads was considered on the discharge piping of the relief valves. • SCC potential was considered on 5 welds. Two weld are located on the 10" piping to the Loop 1 and 3 cold legs. Two welds are on the 6" piping to the Loop 2 hot leg. One weld in on the 8" piping which goes to the Loop 3 hot leg.
SQ	• Thermal Fatigue & Water Hammer	1.5E-04	2.2E-04	• Water hammer is a potential concern for the piping connected to the RH system.

Notes:
* - Disabling leak rate – LLOCA (Large LOCA), MLOCA (Medium LOCA), SLOCA (Small LOCA), and SYS (system disabling leak). When no leak rate is shown, this is the system disabling leak rate.

Table 2
Failure Probability Estimates (without ISI) for Sequoyah Unit 2

System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
AF	• Thermal Fatigue & Water Hammer • Thermal Fatigue & Steam Hammer • Thermal Fatigue, Water Hammer & Striping / Stratification	2.1E-05 1.0E-04 6.8E-04	1.6E-04 - 3.4E-04 6.1E-04 1.8E-04	• Striping/stratification could occur at low-flow conditions near the interface with main feedwater. • In AFW (piping upstream of check valve isolating FW from AFW) check valve leakage could cause thermal striping or stratification. • Water hammer in the FW line could occur from a plant trip. AFW piping connected to the FW line could be affected by the water hammer loading. • Steam hammer could occur in the Main Steam piping. The piping for the turbine driven AFW pumps connected to the Main Steam line could be affected by the steam hammer loading.
BD	• Thermal Fatigue, Steam Hammer & Vibratory Fatigue • Thermal Fatigue, Steam Hammer, and FAC • Thermal Fatigue, Steam Hammer, Vibratory Fatigue, & FAC	1.7E-03 3.2E-01 3.2E-01	4.6E-03 3.2E-01 3.2E-01	• An augmented program for FAC exists for BD piping. • Steam hammer loadings are considered on the BD piping to account for the loading from a steam generator blowdown. • Vibrational loading is considered for the piping connected to the steam generator.

Table 2
Failure Probability Estimates (without ISI) for Sequoyah Unit 2

System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
CH	• Thermal Fatigue • Thermal Fatigue & Vibratory Fatigue • Thermal Fatigue, Vibratory Fatigue, & Water Hammer • Thermal Fatigue, Vibratory Fatigue, & Striping / Stratification	3.5E-06 - 6.7E-04 6.4E-06 – 8.4E-03 1.2E-05 – 8.7E-03 7.0E-05 – 6.1E-04	• SLOCA 1.6E-04 • IE/SYS 4.9E-06 - 2.8E-04 • SLOCA 5.5E-03 • IE/SYS 4.3E-06 – 5.5E-03 1.4E-05 – 5.6E-03 • SLOCA 5.6E-05 – 2.7E-04 • MLOCA 6.1E-05 – 2.2E-04 • IE/SYS 2.8E-05 – 4.0E-04	• The configuration of the charging path to the selected RCS cold leg was identified as potentially susceptible to thermal cycling/fatigue failure when stagnant (NRC Bulletin 88-08). The potential for this failure has been minimized by maintaining flow through the line. • Flashing and cavitation occurs at the letdown orifices which could produce vibratory loadings on the adjacent piping . • Vibratory loadings were considered on the piping connected to the centrifugal charging pumps and the piping connected to the RCL. • Potential for transient loads exists at the discharge of the high capacity pumps and at the discharge relief valves.
CI	• Thermal Fatigue • Thermal Fatigue & Erosion / Corrosion	1.1E-06 – 8.4E-04 6.2E-02	2.2E-07 – 4.8E-04 6.2E-02	• Material wastage was considered for the carbon steel ERCW and Fire Protection piping.

Table 2
Failure Probability Estimates (without ISI) for Sequoyah Unit 2

System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
CS	• Thermal Fatigue • Thermal Fatigue & Water Hammer • Thermal Fatigue & Vibratory Fatigue • Thermal Fatigue, Vibratory Fatigue & Water Hammer	9.8E-05 – 2.0E-04 7.0E-06 – 2.0E-04 2.0E-05 – 2.0E-04 2.0E-05 – 2.0E-04	6.1E-05 – 1.1E-04 3.5E-06 – 2.0E-04 7.2E-06 – 1.2E-04 3.3E-05 – 2.0E-04	• The potential for vibration was considered for the piping adjacent to the CS pumps and the piping adjacent to the throttling orifice. • The potential for water hammer due to gas pockets forming in the pump discharge piping was considered. • The potential for water hammer in the spray header piping was considered.
FW	• Thermal Fatigue, Vibratory Fatigue & Water Hammer • Erosion/Corrosion, Thermal Fatigue & Water Hammer • Thermal Fatigue & Water Hammer • Thermal Fatigue & Vibratory Fatigue • Erosion / Corrosion, Thermal Fatigue, Vibratory Fatigue, Water Hammer & Striping / Stratification • Erosion / Corrosion, Thermal Fatigue, Water Hammer & Striping / Stratification	3.0E-04 3.5E-02 – 4.4E-02 8.8E-08 – 4.6E-04 1.9E-04 4.7E-02 4.7E-02	1.1E-03 3.5E-02 – 4.4E-02 1.9E-08 – 5.3E-03 2.1E-04 4.7E-02 4.7E-02	• Vibration was considered for the piping adjacent to the steam generators. • The potential for thermal striping and stratification was considered for the piping between the AFW connection to the FW line and the steam generator. • FAC was considered for the FW normal flow path piping to the steam generators. The locations where high flow velocities cause pipe wall thinning are in the FAC program. • The piping can experience transient loads during a plant trip.
MS	• Thermal Fatigue & Steam Hammer • Thermal Fatigue, Steam Hammer & Vibratory Fatigue	2.7E-07 – 2.1E-04 2.7E-07	1.3E-04 – 9.4E-04 1.3E-04	• The piping can experience transient loads during a plant trip. • Vibration was considered to occur in the piping adjacent to the steam generators.

Table 2 Failure Probability Estimates (without ISI) for Sequoyah Unit 2				
System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
RC	• Thermal Fatigue • Thermal Fatigue & Vibratory Fatigue • Thermal Fatigue & Striping/Stratification • Thermal Fatigue & Water Hammer	1.4E-09 – 7.9E-05 1.0E-06 – 1.2E-02 6.4E-04 1.8E-07 – 1.2E-05	• MLOCA 1.4E-06 • SLOCA 5.0E-011 – 1.3E-03 • LLOCA 1.7E-06 – 4.2E-06 • MLOCA 9.3E-07 – 6.4E-05 • SLOCA 9.3E-07 – 7.1E-03 • LLOCA 6.6E-04 • MLOCA 6.6E-04 • SLOCA 6.6E-04 • MLOCA 8.1E-05 – 9.2E-05 • SLOCA 8.0E-05 – 1.3E-03	• The RCL piping and the piping connected to the RCL considered vibration. • Thermal striping and stratification occurs in the pressurizer surge line. • Locations where the piping could experience large temperature changes are the pressurizer surge line, tailpipes due to a PORV lifting, and at the Charging nozzles. • Transient loads were considered to occur in the tailpipes due to steam release from pressurizer relief valves.

Table 2
Failure Probability Estimates (without ISI) for Sequoyah Unit 2

System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
RH	• Thermal Fatigue	4.2E-06 – 1.4E-04	7.6E-06 – 1.8E-04	• System experiences temperature changes from ambient to 350°F when used for shutdown cooling. • Vibration was considered for the piping adjacent to the RHR pumps and for the piping connected to the RCL. • Transient loads were considered in the pump discharge piping due to the potential of gas intrusion in the piping. Venting is performed to remove possible gas intrusion thus reducing the probability of water hammer. • The potential for transient loads was considered on the discharge piping of the relief valves. • NRC Bulletin 88-08 Supplement 3 identified potential thermal stratification / striping concerns for RHR piping connected to the RCL. This concern was evaluated and the SQN RHR piping was determined not to be susceptible to unacceptable thermal stress levels.
	• Thermal Fatigue & Vibratory Fatigue	8.5E-06 – 1.9E-04	• SLOCA 2.3E-04 • SYS 3.7E-06 – 7.1E-05	
	• Thermal Fatigue, Vibratory Fatigue & Water Hammer	1.1E-05 – 1.9E-04	2.6E-05 – 1. 5E-04	
	• Thermal Fatigue & Striping / Stratification	1.2E-04	9.1E-05	
	• Thermal Fatigue & Water Hammer	1.1E-05 – 6.7E-04	2.6E-05 – 2.2E-04	
	• Thermal Fatigue, Vibratory Fatigue & Striping / Stratification	4.6E-05	• LLOCA 1.9E-05 • MLOCA 1.6E-05 • SLOCA 1.7E-05 • SYS 1.7E-05	
	• Thermal Fatigue, Vibratory Fatigue, Water Hammer & Striping / Stratification	1.8E-05	• MLOCA 1.5E-05 • SLOCA 1.5E-05 • SYS 1.6E-05	

Table 2 Failure Probability Estimates (without ISI) for Sequoyah Unit 2				
System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
SI	• Thermal Fatigue	3.4E-06 – 7.0E-04	7.4E-07 – 1.7E-04	• Vibration was considered for the piping adjacent to the SI pumps and for the piping connected to the RCL. • There is vibration due to cavitation at the 1-1/2" and 2" needle valves. New orifices have been added to reduce the vibration due to the cavitation. • NRC Bulletin 88-08 identified potential thermal stratification/striping concerns for piping connected to the RCL • Transient loads were considered in the SI pump discharge piping due to potential gas pockets. The potential for gas pockets (due to nitrogen coming out of solution) at high points in the piping exists due to back-leakage through check valves. • The potential for transient loads was considered on the discharge piping of the relief valves.
	• Thermal Fatigue & Water Hammer	6.6E-07 – 2.3E-04	1.1E-05 – 2.0E-04	
	• Thermal Fatigue, Water Hammer & Striping / Stratification	2.7E-04 – 3.2E-04	1.1E-04 – 1.7E-04	
	• Thermal Fatigue, Vibratory Fatigue & Water Hammer	1.9E-05 – 9.0E-04	2.1E-05 – 3.4E-04	
	• Thermal Fatigue, Vibratory Fatigue, Water Hammer & Striping/ Stratification	1.8E-05 – 1.0E-02	• LLOCA 2.8E-05 • MLOCA 1.5E-05 – 2.7E-05 • SLOCA 1.5E-05 – 6.4E-03 • SYS 1.6E-05 – 8.7E-03	
	• Thermal Fatigue & Vibratory Fatigue	2.6E-05 – 1.0E-04	1.4E-05 – 7.4E-05	
SQ	• Thermal Fatigue & Water Hammer	1.5E-04	2.2E-04	• Water hammer is a potential concern for the piping connected to the RH system.

Table 2 Failure Probability Estimates (without ISI) for Sequoyah Unit 2				
System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability range at 40 years with no ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	

Notes:
* - Disabling leak rate – LLOCA (Large LOCA), MLOCA (Medium LOCA), SLOCA (small LOCA), and SYS (system disabling leak). When no leak rate is shown, this is the system disabling leak rate.

NRC Question 2:

Another major step in the WCAP process is assignment of segments into safety significance categories based on integrated decision making process, and the selection of segments for inspection locations. The requested Table 3 summarizes the results of the safety significance categorization process as determined by the quantitative criteria, by the expert panels deliberation on the medium safety significant segments, and by the expert panels deliberations based on other considerations. The summarizing information requested in Table 3 will provide an overview of the distribution of the safety significance of the segments based on the quantitative results, and the final distribution based on the integrated decision making. Each segment has four risk reduction worths (RRWs) calculated, a core damage frequency with and without operator action, and a large early release frequency (LERF) with and without operator action. Please provide the following Table.

System	Number of Segments with Any RRW >1.005	Number of Segments with Any RRW Between 1.005 and 1.001	Number of Segments with Any RRW Between 1.005 and 1.001 Placed in HSS	Number of Segments with All RRW < 1.001 Selected for Inspection

TVA Response:

Tables 3 and 4 provide the information requested in the format agreed to with the WOG in the revised RI-ISI template as Table 3.7-1. The tables below reflect the information at the time of the Expert Panel Meeting based upon the minutes of the meeting. In a few instances the Expert Panel disagreed with the quantitative results presented and requested new quantification based on different assumptions. As a result, the final RRW calculations may vary from the results presented to the Expert Panel. The differences were determined to be minor or supportive of the Expert Panel determinations.

Table 3
Summary of Risk Evaluation and Expert Panel Categorization Results for Sequoyah Unit 1

System	Number of segments with any RRW $\geq$1.005	Number of segments with any RRW between 1.005 and 1.001	Number of segments with all RRW <1.001	Number of segments with any RRW between 1.005 and 1.001 placed in HSS	Number of segments with all RRW < 1.001 selected for inspection	Total number of segments selected for inspection (High Safety Significant Segments)
AF	4	2	8	0	0	0
BD	8	8	2	4	0	12
CH	11	8	70	3	0	13
CI	0	0	117	0	0	0
CS	0	14	13	0	1	1
FW	0	12	33	8	0	8
MS	0	4	14	0	0	0
RC	5	44	74	12	0	17
RH	0	19	9	2	3	5
SI	22	35	58	8	7	33
SQ	0	0	7	0	0	0
Total	50	146	405	37	11	89

Table 4 Summary of Risk Evaluation and Expert Panel Categorization Results for Sequoyah Unit 2						
System	Number of segments with any RRW ≥1.005	Number of segments with any RRW between 1.005 and 1.001	Number of segments with all RRW < 1.001	Number of segments with any RRW between 1.005 and 1.001 placed in HSS	Number of segments with all RRW < 1.001 selected for inspection	Total number of segments selected for inspection (High Safety Significant Segments)
AF	4	4	6	0	0	0
BD	4	12	2	8	0	12
CH	11	8	70	3	0	13
CI	0	0	117	0	0	0
CS	0	14	13	0	1	1
FW	0	12	33	8	0	8
MS	0	4	14	0	0	0
RC	5	48	70	12	0	17
RH	0	19	9	2	3	5
SI	22	35	58	6	7	31
SQ	0	0	7	0	0	0
Total	46	156	399	39	11	87

NRC Question 3:

Another major step in the WCAP process is development of the consequences of segment ruptures. The WCAP methodology requires that a summary of the consequences be developed for each system and provided to the expert panel during their deliberations. Please provide this summary for each system. The summary will illustrate that the appropriate types of consequences (i.e., initiating events, mitigating system failure, and combinations) are included in the evaluation and will provide an overview of the results of the step.

TVA Response:

Table 5 below provides a summary of postulated consequences by system.

Table 5
Summary of Postulated Consequences by System

System	Summary of Consequences
AF - Auxiliary Feedwater	The direct consequences postulated from piping failures from this system are feedline/ steamline breaks, failure of up to two trains of AFW system and loss of the CST. Indirect effects were postulated for AFW segments in which the loss of normal and alternate steam supplies to the AFW turbine-driven pump result due to a steam line break in the west valve vault resulting in the loss of SG #1 and #4 PORVs.
BD - Steam Generator Blowdown	The direct consequences postulated from piping failures from this system include steam line breaks inside and outside containment, loss of the associated normal and alternate steam supply to the TDAFW pump, and failure to isolate the system on a steam generator tube rupture.
CH - Chemical & Volume Control	The direct consequences associated with piping failures are reactor trip on low seal injection flow, small LOCA, loss of one or both CCP trains for injection, recirculation, and emergency boration, loss of RWST outside containment and loss of containment sump recirculation outside containment and outside the crane wall inside containment.
CI – Containment Isolation (Supersystem)	The direct consequences postulated from piping failures from this system are failures of the containment isolation system, failure to isolate the containment purge system, loss of primary makeup water pumps, loss of RCP thermal barrier cooling and loss of component cooling water.

Table 5
Summary of Postulated Consequences by System

System	Summary of Consequences
CS – Containment Spray	The direct consequences associated with piping failures are the loss of containment spray, loss of RHR train spray headers, loss of the RWST outside containment and loss of containment sump recirculation outside containment and outside the crane wall inside containment. An indirect consequence is postulated in the 8" RWST return line (containment spray test return line) in which a piping failure could spray and thus fail the primary water makeup pumps.
FW - Feedwater	The direct consequences postulated from piping failures from this system are loss of main feedwater restoration, loss of the normal and alternate steam supplies to the TDAFW pump, feedline breaks inside and outside containment, and steam flow/ feedwater flow mismatch resulting in a plant trip.
MS – Main Steam	The direct consequences postulated from piping failures from this system are loss of normal and alternate supply to the TDAFW pump, steam line break inside and outside containment, loss of steam dumps and MS ARVs. Indirect effects were postulated for segments in which a steam line break in the west valve vault results in the loss of SG #1 and #4 PORVs and the turbine driven AFW pump. For other segments, a main steam line break in the east valve vault is postulated to result in the loss of SG #2 and 3 PORVs.
RC - Reactor Coolant	The direct consequences associated with piping failures are large, medium and/or small loss of coolant accidents (LOCAs) and loss of ECCS flow to one loop.
RH - Residual Heat Removal	The direct consequences associated with piping failures are the loss of one or both RHR trains for normal shutdown cooling and low pressure injection and recirculation, loss of RWST outside containment and loss of containment sump recirculation outside containment and outside the crane wall inside containment. Several segments involve LOCA initiating events (large, medium and small LOCAs).
SI - Safety Injection	The direct consequences associated with piping failures are the loss of accumulator injection, loss of one or both trains of high pressure injection and recirculation from either the charging system or safety injection system, loss of RWST outside containment and outside the crane wall inside containment, and loss of containment sump recirculation outside containment and outside the crane wall inside containment. Several segments involve LOCA initiating events (large, medium and small LOCAs). An indirect consequence is postulated for one piping segment (24" RWST supply line) in which a piping failure could spray and thus fail the primary water makeup pumps.
SQ – Water Quality and Sampling	The direct consequences postulated from piping failures from this system are the loss of containment sump recirculation outside containment and outside the crane wall inside containment.

NRC Question 4:

Please add the statement that the uncertainty analysis that is described on pages 125 and 129 (Section 3.6.1) of WCAP-14572, Rev. 1-NP-A, was performed. Also, please identify how many segments' RRW increased from below 1.001 to greater than or equal to 1.005 in the uncertainty analysis. If the uncertainty analysis was not performed as described on pages 125 and 129 of WCAP-14572, Rev. 1-NP-A, please provide a description of how the process considered uncertainties and provide the justification for the adequacy of this deviation.

TVA Response:

The uncertainty analysis, as described on WCAP page 125 and 129, was performed and is included as part of the base process. The results of these calculations were provided in Table 3.5-1 of the original submittal. Given that the uncertainty was directly incorporated into the risk evaluation calculations, any chance that segments with RRWs below 1.001 moved to greater than or equal to 1.005 is already captured. For this RAI a comparison between the RRW values before and after uncertainty analysis was made. This comparison showed that no segments had an increase in RRW value from less than 1.001 to greater than or equal to 1.005.

NRC Question 5:

Please state that the change in risk calculations were performed according to all the guidelines provided on page 213 (Section 4.4.2) of WCAP-14572, Rev. 1-NP-A, or provide a description and justification of any deviation.

TVA Response:

The change in risk calculations was performed according to all the guidelines provided on page 213 of the WCAP with one exception. Per the WCAP, credit is taken for leak detection for the RCS piping segment failure probabilities. The change in risk methodology used for Sequoyah Units 1 and 2 extended this to segments located inside containment and that interface with the RCS (systems such as SI, CVCS, RHR, etc.) such that radiation monitors and sump level will detect a leak. For these segments the failure probability "with ISI" for those being inspected by NDE and without ISI for those not being inspected is used along with credit for leak detection.

NRC Question 6:

The quantitative change in risk results are adequately summarized in the current template Tables 3-5 and 3-10. Please state that all four criteria for accepting the final selection of inspection locations provided on pages 214 and 215 (Section 4.4.2) of WCAP-14572, Rev. 1-NP-A were applied. If all four criteria were not used, please provide a description and justification of the deviation. If comparison with any of the criteria indicated that reevaluation of the selected locations was needed, please identify the criteria that required the reevaluation and summarize the results of the reevaluation. If the results of the reevaluation can be found in the footnotes of Table 5-1, please refer to the footnotes.

TVA Response:

The change in risk calculations were performed according to all the guidelines provided on pages 210 through 215 of the WCAP. The approach evaluated the change in risk with the inclusion of the probability of detection as determined by the SRRA model. Adjustments were made to add segments until all four criteria for accepting the results discussed on page 214 and 215 in the WCAP were met. This evaluation resulted in the identification of four piping segments for Sequoyah Unit 1 and five piping segments for Sequoyah Unit 2 for which examinations are now required (systems identified in Tables 5-1 and 5-2 via a footnote).

The criteria requiring reevaluation of the selected locations by WCAP-14572 were the risk increase for a given system in CDF and LERF in moving from the current Section XI program to the RI-ISI program. All additional inspections were added to meet these criteria.

For Sequoyah Unit 1, Main Steam and Residual Heat Removal initially had unacceptable risk increases for CDF and LERF. Main Steam needed reevaluation due to increases for CDF with operator action, CDF without operator action, LERF with operator action, and LERF without operator action. Residual Heat Removal was reevaluated for CDF without operator action and LERF without operator action. One additional segment was added to Main Steam, and three additional segments were added to Residual Heat Removal. TVA elected to perform exams on a total of five structural elements on these four segments as identified on Table 5-1.

TVA Response (continued):

For Sequoyah Unit 2, Residual Heat Removal and Safety Injection initially had unacceptable risk increases for CDF and LERF. Residual Heat Removal was reevaluated due to increases in CDF without operator action and LERF without operator action. Safety Injection was reevaluated for CDF without operator action, CDF with operator action, and LERF without operator action. Three segments were added to Residual Heat Removal and two segments were added to Safety Injection. TVA elected to perform exams on a total of six structural elements on these five segments as identified on Table 5-2.

NRC Question 7:

Briefly describe the qualifications, experience, and training of the users of the SRRA code on the capabilities and limitations of the code.

TVA Response:

An engineering team was established that has access to expertise from ISI, NDE, materials, stress analysis and system engineering. Each of the team members has at least 10 years of experience in their respective disciplines. The team is knowledgeable of the potential piping degradation mechanisms and loading conditions associated with the operation of Sequoyah Units 1 and 2.

The team was trained in the failure probability assessment methodology and the Westinghouse structural reliability and risk assessment (SRRA) code, including identification of the capabilities and limitations as described in WCAP-14572, Revision 1-NP-A, Supplement 1. The training was performed in both classroom and hands-on sessions. Technical reviews of the SRRA calculations were performed by both the TVA and Westinghouse engineers who are cognizant of the structural reliability requirements. Continuous guidance was provided by cognizant Westinghouse SRRA specialists throughout the duration of the development of the risk-informed ISI program for Sequoyah Units 1 and 2.

NRC Question 8:

Please provide the following information regarding the treatment of augmented programs during the RI-ISI program development.

a) Treatment of augmented program inspections during categorization is described on page 80 (Section 3.5.5) of WCAP-14572, Rev. 1-NP-A. Please add the statement that the effects of ISI of existing augmented programs are included in your calculations used to categorize the segments or provide a description and justification of any deviation.

b) When the SRRA code is used for calculating failure probabilities for FAC, please describe if calculations were coordinated with the existing plant program since the code requires input that can be obtained from the knowledge gained from ongoing monitoring and evaluations of wall thinning rates.

TVA Response:

Item a:

The effects of ISI of existing augmented programs are included in the risk evaluation used to assist in categorizing the segments as described on pages 80 and 105 of WCAP-14572. There were no deviations. The failure probabilities used in the risk-informed process are documented and maintained in the plant records.

Item b:

When the SRRA code is used for calculating failure probabilities, the data used for FAC was coordinated with the existing plant program. The locations of piping subject to FAC and the associated wastage values were obtained from the FAC representative of Corporate Material Engineering group. The FAC representative coordinated with the plant personnel responsible for the ongoing monitoring programs to determine the wall thinning rates. Information provided by the FAC representative is documented in the SRRA calculations.

NRC Question 9:

Please confirm that SRRA code was only used to calculate failure probabilities for the failure modes, materials, degradation mechanisms, input variables, and uncertainties it was programmed to consider as discussed in the WCAP Supplement 1, page 15. For example, the SRRA code should only be applied to standard piping geometry (circular piping geometry with uniform wall thickness). If the code was applied to any non-standard geometry, please describe how the SRRA inputs were developed.

TVA Response:

The SRRA code was only used to calculate failure probabilities for the failure modes, materials, degradation mechanisms, input variables, and uncertainties it was programmed to consider as discussed in the WCAP Supplement 1. The SRRA code was only applied to standard piping geometry (circular piping geometry with uniform wall thickness). The SRRA code was not applied to any non-standard geometry. Each SRRA calculation lists the limitation of the SRRA code for the piping in the TVA RI-ISI program and provides a statement that the limitations did not exist for the piping segments evaluated in the calculation.

NRC Question 10:

Please describe any sensitivity studies performed to support the use of the SRRA code.

TVA Response:

During and after the SRRA training provided by Westinghouse, the effects of various input parameters, such as SCC potential, were investigated via unofficial SRRA runs that are not part of the RI-ISI program database. During the RI-ISI program most sensitivity studies were performed to determine the design limiting conditions for pipe break conditions. The following events and their probability of occurrence were considered in sensitivity studies as appropriate:

- normal operation,
- potential water hammer events,
- potential faulted design events such as a seismic event, and
- potential failure of snubbers.

TVA Response (continued)

The SRRA code was then used to calculate failure probabilities for the failure modes, materials, degradation mechanisms, input variables, and uncertainties it was programmed to consider. The failure probabilities of the SRRA evaluations were reviewed to determine if they represented expected results for the plant conditions evaluated. If necessary, the SRRA input parameters were adjusted to account for actual plant conditions such as vibration for systems which do no operate continuously, potential thermal stratification and striping concerns addressed in NRC Bulletins 88-08 and 88-11, material wastage or other input parameters which were judged to either over-or-under estimate the failure probabilities of a segment.

NRC Question 11:

Table 5-1 indicates that 74 Class 1 elements were selected for the Unit 1 RI-ISI program and Table 5-2 indicates that 69 Class 1 elements were selected for the Unit 2 RI-ISI program. For each unit, what is the total number of Class 1 butt welds and what percentage of these welds were selected for volumetric inspection in the RI-ISI program? For each unit, what is the total number of Class 1 socket welds greater than 1-inch in size and what percentage of these welds were selected for inspection in the RI-ISI program?

TVA Response:

The SQN units 1 and 2 ISI program utilizes Paragraph IWB-1220 of the 1989 Edition of ASME Section XI. This paragraph permits Class 1 piping of 1" nominal pipe size (NPS) and smaller to be exempt from surface and volumetric examination. Therefore, weld counts for piping 1" NPS and smaller are not tracked for the ISI program.

SQN unit 1 includes 390 Class 1 circumferential butt welds greater than 1" nominal pipe size (NPS) and 18 Class 1 branch connection welds greater than 2" NPS which results in a total of 408 Class 1 butt welds (weld numbers are based on plant procedure 0-SI-DXI-000-114.2 revision 10, "ASME Section XI ISI/NDE Program Unit 1 and Unit 2"). Branch connection welds less than or equal to 2" NPS are covered by Request for Relief 1-RI-ISI-2 and are not included in the totals above. Forty-three Class 1 butt welds have been selected for volumetric examination for the SQN unit 1 RI-ISI Program. This results in 10.5 % of these 408 Class 1 butt welds being selected for volumetric examination.

TVA Response (continued)

SQN unit 2 includes 376 Class 1 circumferential butt welds greater than 1" NPS and 18 Class 1 branch connection welds greater than 2" NPS which results in a total of 394 Class 1 butt welds (weld numbers are based on plant procedure 0-SI-DXI-000-114.2 revision 10, "ASME Section XI ISI/NDE Program Unit 1 and Unit 2"). Branch connection welds less than or equal to 2" NPS are covered by Request for Relief 2-RI-ISI-2 and are not included in the totals above. Thirty-eight Class 1 butt welds have been selected for volumetric examination for the SQN unit 2 RI-ISI Program. This results in 9.6 % of these 394 Class 1 butt welds being selected for volumetric examination.

SQN unit 1 includes 574 Class 1 socket welds greater than 1" NPS, and SQN unit 2 includes 496 Class 1 socket welds greater than 1" NPS (weld numbers are based on plant procedure 0-SI-DXI-000-114.2, revision 10, "ASME Section XI ISI/NDE Program Unit 1 and Unit 2"). TVA has not identified any active or postulated piping failure mechanisms that initiate from the outside diameter. Volumetric examinations of socket welds for active or postulated piping failure mechanisms that initiate from the inside diameter are not practical and are covered by Request for Relief 1-RI-ISI-2 and 2-RI-ISI-2. High safety significant segments that contain socket welds will be VT-2 examined during system pressure tests. All socket welds within the segment will be VT-2 examined. Therefore, specifying a percentage of Class 1 socket welds selected for examination for the RI-ISI program would not be meaningful.

The following paragraphs provide additional information beyond question 11 that alter the numbers contained in Table 5-1 and Table 5-2 (provided in Attachment 1) for VT-2 examinations for the SI system. TVA identified the needed changes during the preparation of this RAI response.

Table 5-1 as previously submitted required a VT-2 examination of the entire segment for 11 segments and a VT-2 examination of a portion of the segment for 2 segments of the Class 1 SI system. Table 5-1 is revised to require a VT-2 examination of the entire segment for all of these segments. The table was also revised to delete one segment requiring VT-2 examination of the entire segment for the Class 2 SI system. This segment is a Class 1 SI segment that was counted for both Class 1 and Class 2 totals. This results in a required VT-2 examination of the entire segment for 13 segments and a VT-2 examination of a portion of the

TVA Response (continued)

segment is no longer required for any segments of the Class 1 SI system. The number of segments requiring a VT-2 examination for the entire segment for the Class 2 SI system decreases from seven segments to six segments. A revised Table 5-1 is enclosed. There are no changes in the number of volumetric examinations to be performed.

Table 5-2 as previously submitted required a VT-2 examination of the entire segment for 11 segments and a VT-2 examination of a portion of the segment for 2 segments of the Class 1 SI system. Table 5-2 is revised to require a VT-2 examination of the entire segment for all of these segments. This results in a required VT-2 examination of the entire segment for 13 segments and a VT-2 examination of a portion of the segment is no longer required for any segments of the Class 1 SI system. A revised Table 5-2 is enclosed. There are no changes in the number of volumetric examinations to be performed.

NRC Question 12:

Section 3.4 of the submittal states that, "The engineering team that performed this evaluation used the Westinghouse structural reliability and risk assessment (SRRA) software program . . . to aid in the process." Page 83 (Section 3.5.6) of WCAP-14572, Rev. 1-NP-A, states that for Westinghouse Owners Group (WOG) plant application "(SRRA) tools were used to estimate the failure probabilities for the piping segment." Pages 6 and 7 of the related safety evaluation (SE Section 3.2.3) also state that the failure probability estimate of the weld "is subsequently used to represent the failure probability of the segment." Please explain how the quantitative SRRA results were used and how the method comports with WCAP-14572, Rev. 1-NP-A, and the associated SE. If the quantitative results were not directly used as input into the calculations, please describe what failure probability values were used and the basis for the selection of these values.

TVA Response:

The failure probabilities for Sequoyah Units 1 and 2 were calculated using the Westinghouse Windows version of the structural reliability and risk assessment (SRRA) software program. These failure probabilities were used directly as inputs into the calculations. As such, no deviation from the methodology described in WCAP-14572, Rev. 1-NP-A was made.

NRC Question 13:

For the different reactor coolant system loss-of-coolant accident (LOCA) break sizes in the Sequoyah Revision 1 probabilistic risk assessment (PRA) model and for this risk-informed application, what conditional core damage probability (CCDP) and conditional large early release probability (CLERP) values were applied for each break size? If the CCDP and/or CLERP values are location dependent, please provide the range of estimates?

TVA Response:

The information for the different LOCA break sizes as requested is provided below. This information was taken from TVA calculation SQN-MEB-MDN0999-990077, Revision 0.

LOCA Break Sizes	PRA CDF/CDP Result	PRA LERF/LERP Result
Large LOCA	8.0E-03 to 8.5E-03	6.2E-05 to 6.5E-05
Medium LOCA	3.0E-03	2.7E-05
Small LOCA	2.2E-03	2.1E-05

NRC Question 14:

This submittal is based on the Sequoyah Revision 1 PRA model.

1) A previous RI-IST submittal cited a LERF value for the Sequoyah Revision 1 model that is a factor of five greater than the value cited in this submittal. What major enhancements, changes, and assumptions were incorporated into the Sequoyah Revision 1 model that accounts for this reduction in LERF? Please describe how these changes affect this application.

2) How does the peer-reviewed Draft-Revision 2 model differ from the Sequoyah Revision 1 model used in this application? Please describe the differences between the Revision 1 and Draft-Revision 2 model, its affect on this application, and how these differences were considered in this application. Also, please describe the WOG Probabilistic Safety Assessment Peer Review findings and observations that

affect this application (e.g., LOCA, main steam line break, feedwater line break and reactor coolant pump seal LOCA analyses, success criteria, operator recovery actions, modeling, and associated system logic), what impacts these findings and observations have on this application, and if/how these impacts were considered in this application.

TVA Response:

Item 1:

The LERF value cited in the RI-IST submittal was based on the Revision 1 model (see Reference 3) with the original IPE Level 2 model methodology (see reference 1) and is consistent with the definition used in the original SQN IPE. The original IPE Level 2 analysis for SQN grouped the Level 2 release categories into four groups. The first two groups of release categories (i.e., Group I - Large, Early Containment Failures and Large Bypasses, and Group II - Small, Early Containment Failures and Small Bypasses) were then combined to give the large, early release frequency. This combination of all sequences from Group I and Group II into the LERF definition was therefore conservative.

Given the conservatism inherent in this approach, the LERF model was updated in January, 2000 (see Reference 2). A review was performed of current definitions of Large Early Release Frequency (LERF) found in the published literature since the IPE for Sequoyah was completed.

The following references were reviewed:

1. USNRC Regulatory Guide 1.174
2. USNRC Regulatory Guide 1.175
3. ASME PRA Standard - Draft
4. PSA Procedures Guide
5. Westinghouse Owners Group Guidance

The Westinghouse Owners Group Guidance definition and guidance was adopted for the LERF model and incorporated into SQN IPE Revision 1 model and used for the RI-ISI. In summary, the WOG guidance for assigning core damage sequences to LERF was implemented in the revised IPE model for Sequoyah. Release categories assigned to major release Groups I and II during the IPE are assigned to large, early release. There are just two exceptions. Sequences

TVA Response (continued):

involving at most a small containment isolation failure are not to be considered large enough to be included in the LERF frequency. Also, steam generator tube rupture sequences with an unisolated secondary side are not to be included, provided high pressure injection is successful. Such sequences do not result in an early release, as measured from the time of event initiation.

Therefore, the updating of the LERF model and the inclusion of more realistic assumptions resulted in the reduction of LERF by a factor of approximately 5.

References

1. Sequoyah Nuclear Plant Unit 1 Probabilistic Risk Assessment Individual Plant Examination, Revision 0, September 1992.
2. "LERF Models for Sequoyah and Watts Bar", January 2000, RIMS No. B45 000516 001.
3. Sequoyah Nuclear Plant Unit 1 Probabilistic Risk Assessment Individual Plant Examination, Revision 1, RIMS No. B38 960806 800.

Item 2

Discussion of Changes

The Draft-Revision 2 PSA Model which received the WOG PSA Peer Review is based on the Revision 1 PSA Model used in the RI-ISI application. The changes made to the Revision 1 PSA Model, which resulted in the Draft-Revision 2 PSA Model, are summarized in Table 14A. The net result of the changes made to the Revision 1 PSA Model to arrive at the Draft-Revision 2 PSA Model is an 87% decrease in core damage frequency (CDF).

The findings of the WOG PSA Peer review which significantly affect the results of the Draft-Revision 2 PSA Model are listed in Table 14B along with a description of the changes to the Draft-Revision 2 PSA Model to address each finding. Following incorporation of these changes into the Draft-Revision 2 PSA Model, the resulting CDF is 33% of the CDF in the Revision 1 PSA Model. This version of the Sequoyah PSA which addresses the significant findings of the WOG PSA Peer review is referred to as the Revision 2 PSA Model.

TVA Response (continued):

A comparison of the results from the Revision 1 and Revision 2 PSA Models is given in Tables 14C, 14D, and 14E.

Impact on Risk Informed ISI Submittal

The greatest decrease in CDF from the Revision 1 PSA Model to the Revision 2 Model is due to a decrease in initiating event frequencies (item 2 of Table 14A). However, changes in initiating event frequencies do not affect the RI-ISI evaluation since conditional core damage probability (CCDP), is unchanged by the initiating event frequency. The change in CCDP between the Revision 1 and Revision 2 PSA Models for those initiating events which affect the RI-ISI application, are discussed in the following Table:

Initiating Event	Change in CCDP	Reason for Change
Small unisolable LOCA (RCP seal failure)	-5%	Data improvement, offset by Peer Review comments on RWST refill
Medium LOCA	-16%	Data improvement, primarily RHR availability and reliability
Large LOCA	-17%	Data improvement, primarily RHR availability and reliability
Steamline Break Inside Containment	-26%	Data improvement for various plant systems
Steamline Break Outside Containment (also used to model feedwater line break)	-22%	Data improvement for various plant systems

In general, the Revision 2 PSA Model shows an improved plant response (i.e. a decrease in CCDP, given that the initiating event has occurred). The CCDP for the unisolatble small break LOCA (SLOCAN) did not decrease as much as the other initiating events given above, primarily due to the model logic change which no longer credits RWST refill during a SLOCAN (see item 2 of Table 14B). As a result SLOCAN comprises 35% of CDF in the Revision 2 PSA Model versus 25% in the Revision 1 PSA Model.

The only success criteria change between the Revision 1 and Revision 2 PSA Models is that the number of pressurizer power-operated relief valves (PORVs) required for feed and bleed cooling (F&BC) has decreased from 2 to 1 (see item 8 of Table 14A). The

TVA Response (continued):

effect of this change is that F&BC is slightly more resilient in the Revision 2 PSA Model; however, operator error still dominates failure to establish F&BC.

Operator actions and their associated error probabilities remain somewhat constant between the Revision 1 and Revision 2 PSA Models. However, operator actions increased in importance in the Revision 2 PSA Model (see Table 14E) since plant hardware is more reliable in the Revision 2 PSA Model.

The most significant change to system modeling between the Revision 1 and Revision 2 PSA Model is the modeling of divisional separation in the service water system during strainer maintenance (see item 6 of Table 14A). Again, this change increased the resilience of the service water system.

The Revision 2 model was in development at the time of completion of the RI-ISI submittal. As a result, its conclusions have not been incorporated into the RI-ISI program nor submittal. However, given the general improvement in plant response to initiating events, including those induced by pipe failure, the Revision 2 PSA Model does not introduce new accident scenarios which would result in a change to the safety-significance categorization of pipe segments.

Table 14A

	Description of the Change Made to the Revision 1 PSA Model	%Δ CDF
1	Incorporates plant equipment availability and reliability data from June, 1994 to June, 1999. CDF decreased since plant equipment is both more available and more reliable than modeled in the Revision 1 PSA Model	-17
2	Incorporates plant initiating event data from October, 1995 through June, 1999 and initiating event data from NUREG/CR-5750. CDF decreased since initiating event frequencies are lower than used in the Revision 1 PSA Model	-40
3	Removes initiating events for the loss of power to a 6.9 kV shutdown board. This model change is based on electric power system design and plant operating experience which establishes a reactor trip does not occur for these support system failures.	-5
4	Increases the time the plant is above 40% power to 100% of the year to be consistent with recent operating experience. CDF increased since during an ATWS, turbine trips below 40% power are modeled as being less severe (i.e. do not require main feedwater or turbine trip).	0.5
5	Revised modeling of the Shutdown Bus to correctly model bus availability following recovery of off-site power when the shutdown bus failure was due to a failure to separate the bus from the grid.	-10
6	Revised modeling of the essential service water system to correctly model divisional separation during strainer maintenance. This change reduced the contribution to CDF of floods in the service water pump house.	-6
7	Reset the fuel oil mission time to 24 hours (i.e., the same as the diesel generator mission time).	0.5
8	Revised success criteria from 2 to 1 pressurizer power operated relief valve required for feed and bleed cooling.	-10
9	Increased the probability of recovery of the turbine driven auxiliary feedwater pump during a station blackout event from 0.2 to 0.4 based on a detailed analysis of the failure mechanisms for this pump.	-7
10	Reduced the failure probability for the control power system by a factor of 3. This was done by correcting an error in the modeling of the system which double counted system failures induced by a loss of off-site power.	-10
11	Increased the allowable time to trip the reactor coolant pumps (RCPs) following a loss of oil cooling from 2 minutes to 10 minutes. This change allows a decrease in the operator error probability and reduces probability of RCP seal failure.	-5
12	Incorporated the RCP seal modeling guidelines from WCAP-15603 (WOG 2000 Reactor Coolant Pump Seal Leakage Model).	-15
13	Revised the electric power recovery logic and long term recovery factors based on diesel generator recovery and off-site power recovery.	2
14	Correct an error in the modeling of the pressurizer sprays. This error resulted in both spray valves being powered from the same division of control power.	-0.2
15	Enabled RWST makeup following small break LOCA. This design feature was previously described in the Revision 1 PSA Model report, but not previously enabled.	-26

Note: The %ΔCDF is intended to provide an estimate of the magnitude of the described change on CDF. Since baseline CDF changed as the Draft-Revision 2 Model was being developed, the sum of these % changes exceed 100%.

Table 14B

	WOG PSA Peer Review Observation	Description of the Change Made to the Draft-Revision 2 PSA Model	%ΔCDF *[Relative to Draft-Rev 2]*
1	The component cooling and service water systems initiating event frequencies are overly optimistic due to insufficient modeling of common cause failures and mission (exposure) times.	Based on common cause failure data in the NUREG-CR/5497 data base, the common cause terms for service water was revised along with the initiating event frequencies for partial and total loss of component cooling and service water systems.	1.6
2	Refilling RWST is generally not credited in most PSAs due to uncertainties and lack of procedural guidance.	Based on lack of specific procedures and the limited time available to perform this action for a small LOCA, makeup to the RWST was removed from the model.	26
3	The reactor coolant pump (RCP) seal model does not account for a high pressure melt ejection during a station blackout (SBO) when RCP seals remain intact. As presently modeled, seals fail during a SBO resulting in depressurization of the reactor coolant system. This RCP seal modeling underestimates the number of accident sequences that result in early containment failure due to core melt impingement on the containment vessel.	The RCP seal model was modified so that RCP seals failed probabilistically, instead of a guaranteed failure, during SBO scenarios. This increases the contribution to LERF from SBO. However, since RCP seals fail probabilistically, more SBO scenarios no longer result in core damage due to the increased time available to recover power.	-8
4	The Draft-Revision 2 PSA Model has not converged at a truncation cutoff of 1E-9	Additional sensitivity studies established model convergence at a truncation cutoff of 1E-12.	8

Table 14C

Initiating Event Group Contributions to Core Damage Frequency		
	Revision 1	**Revision 2**
CDF (1/reactor-year)	**3.77E-5**	**1.26E-5**
LERF (1/reactor-year)	**5.98E-7**	**2.62E-7**
Accident Sequence Group	**(% of CDF)**	**(% of CDF)**
Loss of Coolant Accidents (LOCAs)	34.1	39.1
Support System Faults	25.1	25.6
Internal Floods	11.1	2.5
Loss of Offsite Power (LOSP)	10.5	2.8
Steam Generator Tube Rupture (SGTR)	9.7	23.7
Transients	8.2	1.0
Anticipated Transient without Scram (ATWS)	1.2	5.2
Interfacing Systems LOCAs	0.1	0.3

Table 14D

Dominant Accident Sequences Contributing to Core Damage		
Accident Sequence Description	Percent of Total CDF	
	Revision 1	Revision 2
Small LOCA followed by failure of swapover from RWST to sump.	17.5	16.1 (#1)
Steam generator tube rupture followed by failure to makeup RWST and failure to depressurize RCS.	7.4	13.6 (#2)
Loss of Battery Board II followed by failure of the AFW turbine-driven pump and failure of the AFW motor-driven pump A and no recovery.	4.0	No longer dominant. See item 8 of Table 14A
Loss of Battery Board I followed by failure of the AFW turbine-driven pump and failure of the AFW motor-driven pump B and no recovery.	4.0	No longer dominant. See Item 8 of Table 14A
Small LOCA followed by failure of RHR pumps A and B and failure to makeup RWST.	3.2	2.9 (#7)
ERCW Train `A' strainer room flood with independent failure of ERCW Train `B' leading to RCP seal LOCA and failure of ECCS.	2.9	No longer dominant. See item 6 of Table 14A
ERCW Train `B' strainer room flood with independent failure of ERCW Train `A' leading to RCP seal LOCA and failure of ECCS.	2.9	No longer dominant. See Item 6 of Table 14A

(#'s indicate ranked sequence number in the Revision 2 PSA Model)

Table 14E

Important Operator Actions		
Operator Action	**Percent (Rev 1)**	**Percent (Rev 2)**
Align High-Pressure Recirculation, Given Swapover Succeeds	18.7	26.5
Cool Down and Depressurize RCS, Given an SGTR	7.5	15.9
Stop RCPs on Loss of Train A CCS or RCP Cooling Path	6.5	9.0
Makeup RWST Inventory, Given LOCA with Loss of Recirculation	3.3	Not credited
Makeup RWST Inventory Following a SGTR Event	3.1	10.3

NRC Question 15:

Section 3.8 indicates that there were 61 segments at Unit 1 and 54 segments at Unit 2 that were placed in Region 1 of Figure 3.7-1 of WCAP-14572, Rev. 1-NP-A. There are also 28 segments at Unit 1 and 33 segments at Unit 2 that were placed in Region 2.

a) What is the breakdown of Class 1 and 2 piping segments in Region 1?

b) How many elements are in Region 1a? Are there any segments in Region 1 that do not have an element in Region 1a? If so, please identify these segments and explain why these segments do not have an element in Region 1a.

c) It is expected that there would be at least two elements selected for inspection for every segment that is in Region 1 (all Region 1a elements not in an augmented program, which should be at least one for every segment, and Region 1b elements selected for every segment using an acceptable statistical evaluation process, which should also be at least one for every segment) and one element selected for inspection for every segment that is in Region 2 (using an acceptable statistical evaluation process, which should be at least one for every segment). Based on the information provided in Section 3.8 of the submittal, the minimum number of RI-ISI elements expected is 150 [61(Region 1a)+61(Region 1b)+28(Region 2)] at Unit 1 and 141 [54(Region 1a)+54(Region 1b)+33(Region 2)] at Unit 2, however, there are only 140 and 135 respectively. Please explain the difference in the expected number of selected elements and the actual number of elements selected.

TVA Response:

Item a:

SQN1			SQN2	
Region 1			Region 1	
Class 1 Segments	Class 2 Segments	System	Class 1 Segments	Class 2 Segments
0	12	BD	0	12
11	2	CH	11	2
0	8	FW	0	8
7	0	RC	6	0
15	6	SI	12	5
33	28	Total	29	27

Note: The Sequoyah Unit 2 Region count should be 56 segments in Region 1 and 31 segments in Region 2. This supersedes the region count provided previously by TVA letter dated March 23, 2001.

Item b:

All segments in Region 1 for Sequoyah Units 1 and 2 have an element to be examined in Region 1A. For Sequoyah Unit 1 there are:

- 6 segments with 9 welds selected for inspection using a volumetric exam
- 16 segments with locations within a FAC program and VT-2
- 38 segments with areas subject to VT-2 at specific locations
- 1 segment with an augmented program on 2 draw bead welds (not placed in the count since the welds are not B-F or B-J)

for a total of 61 segments in Region 1. Additional details are provided in the following table for segments in Region 1A that are solely examined by FAC and/or VT-2.

TVA Response to Item b continued:

Sequoyah Unit 1	
Segments	Comments
BD-005,006,007,008,009, 010,011,012,017,018,019,020	Segments contain only socket welds FAC program for BD-009 through 012 and 017 through 020
CH-003B,004B,020	Segments contain only socket welds and branch connection welds
CH-030,031,032,033	Socket welds drive failure importance and are placed in region 1A One butt weld in each segment was selected for inspection in region 1B
CH-034,035,036,037	Segments contain only socket welds
FW-005,006,007,008, 009,010,011,012	FAC program for 1A portion of each segment
RC-036,050,052,053,054	Segments contain only socket welds and branch connection welds
SI-021B,022B,023B,024B, 055B,056B,069,070,071, 072,079B,088	Segments contain only socket welds and branch connection welds
SI-058A,077B	Socket welds drive failure importance and are placed in region 1A One butt weld in each segment was selected for inspection in region 1B
SI-073,074,075,076	Segments contain only socket welds

Within Region 1A for Sequoyah Unit 2, there are:

- 3 segments with 6 welds selected for inspection using a volumetric exam
- 16 segments with locations within a FAC program and VT-2
- 37 segments with areas subject to VT-2 at specific locations

for a total of 56 segments in Region 1. Additional details are provided in the following table for segments in Region 1A that are solely examined by FAC and/or VT-2.

TVA Response to Item b (continued):

Sequoyah Unit 2	
Segments	Comments
BD-005,006,007,008,009, 010,011,012,017,018,019,020	Segments contain only socket welds FAC program for BD-009 through 012 and 017 through 020
CH-003B,004B,020	Segments contain only socket welds and branch connection welds
CH-030,031,032,033	Socket welds drive failure importance and are placed in region 1A One butt weld in each segment was selected for inspection in region 1B
CH-034,035,036,037	Segments contain only socket welds
FW-005,006,007,008, 009,010,011,012	FAC program for 1A portion of each segment
RC-036,050,052,053,054	Segments contain only socket welds and branch connection welds
SI-021B,022B,023B,024B, 055B,056B,069,070,071, 072,079B	Segments contain only socket welds and branch connection welds
SI-057A,058A	Socket welds drive failure importance and are placed in region 1A One butt weld in each segment was selected for inspection in region 1B
SI-073,074,075,076	Segments contain only socket welds

TVA Response to Item c:

There are several reasons for having a different number of inspections or elements than predicted by the simple formula for the minimum number expected for Regions 1A, 1B, and 2.

The following items account for the difference between the expected number of inspections and those identified in Table 5-1 for Sequoyah Unit 1:

- There are 13 exams added for defense-in-depth (8) and delta-risk (5) considerations.
- There are 6 segments that have more than the minimum number of inspections for a region for a total of 11 inspections above the minimum.
- There are 7 segments where both a butt weld and a VT-2 inspection are identified for a given Region (1A, 1B, or 2).

TVA Response to Item c (continued):

Since only a single exam is expected for each Region (1A, 1B, or 2), this represents seven inspections above the expected number of inspections.

- There are 40 Region 1 segments that contain only socket welds that are solely examined by VT-2.
- Segment RC-051 has an augmented program on two draw bead welds (not a B-F or B-J weld) and therefore has one less exam than expected.
- A portion of segment SI-077B was combined with segment SI-077A to form one aggregate lot which resulted in one less exam than expected. (Note 1)

Starting with 150 expected exams and adding 13 + 11 + 7 and subtracting 40 + 1+ 1 yields 150+13+11+7-(40+1+1)=139. Upon completion of the detailed summary of the proposed RI-ISI inspection locations in the new Table 5-1, note that there are now only 139 locations.

The following items account for the difference between the expected number of inspections and those identified in Table 5-2 for Sequoyah Unit 2:

- There are 14 exams added for defense-in-depth (8) and delta-risk (6) considerations.
- There are 6 segments that have more than the minimum number of inspections for a region for a total of 11 inspections above the minimum.
- There are seven segments where both a butt weld and a VT-2 inspection are identified for a given Region (1A, 1B, or 2). Since only a single exam is expected for each Region (1A, 1B, or 2), this represents seven inspections above the expected number of inspections.
- There are 39 Region 1 segments that contain only socket welds that are solely examined by VT-2.
- A portion of segment SI-077B was combined with segment SI-077A to form one aggregate lot which resulted in one less exam than expected. (Note 1)

Starting with 143 expected exams (Note 2) and adding 14 + 11 + 7 and subtracting 39 and 1 yields 143+14+11+7-(39+1)=135

(Note 1): The butt welds from segments SI-077A and SI-077B were combined into an aggregate lot using the process on page 174 and 175 of WCAP-14572. The resultant aggregate lot confidence was greater

TVA Response to Item c (continued)

than 95% and thus a single exam location could be selected from segment SI-077A or SI-077B to represent the butt welds on SI-077A and SI-077B.

(Note 2):The Sequoyah Unit 2 region count should be [(56 region 1a) + (56 region 1b) + (31 region 2)]

NRC Question 16:

What specific value(s) was(were) used to differentiate between High Failure Importance and Low Failure Importance in Figure 3.7-1 of WCAP-14572, Rev. 1-NP-A? Please include the break size and frequency (or 40-year probability).

TVA Response:

The WCAP identifies a range of values (1E-4 to 1E-3) for a large leak 40-year failure probability that can be used as an initial indicator between high and low failure importance. This "range" is provided because there is no single value of failure probability that corresponds to the boundary between high and low failure importance. Generally, if the probability of a large leak (defined as the system disabling leak rate in response to question 1) at 40 years exceeds 1E-04, the segment was categorized as high failure importance (HFI). However, if the engineering subpanel determined that there was no active failure mechanism known to exist and the segment was not analyzed as being highly susceptible to a failure mechanism that could lead to leakage or rupture, the segment was categorized as Region 2.

NRC Question 17:

Section 3.8 indicates that 9 segments at Unit 1 and 7 segments at Unit 2 are outside the applicability of the model or had only one weld in the segment. How many segments were considered outside the applicability of the model (as opposed to having only one weld) and why? Please describe what failure probability values were used for these segments and provide the basis for selection of these values.

TVA Response:

Three segments in each unit had more than one butt weld and were considered outside of the applicability of the model.

TVA Response (continued):

All of these segments have thin-walled piping with low temperatures and pressures and no active degradation mechanisms. In all cases the segments did not receive a pre-service radiographic exam (an important input to Win-SRRA). These 3 segments, CS-012, RH-018, and SI-049 had 40-year large leak failure probabilities, as calculated by the SRRA code, of 6.1E-05, 8.7E-05 and 1.3E-04 respectively. Even through segment SI-049 falls within the "range" for indication of high failure importance ($P_{large\ leak}$ > 1E-03 to 1E-04), this segment did not meet the standard definition for high failure importance. It does not have either an active failure mechanism that is known to exist, or alternatively it has not been analyzed as being highly susceptible to a failure mechanism that could lead to leakage or rupture. For these reasons, the three segments (CS-012, RH-018, and SI-049) are categorized as low failure importance (Region 2, because they are high safety significant). The Perdue model is too conservative for this situation where the piping segments have no pre-service radiographic exam but are highly reliable, and they have no aggressive degradation mechanism. The guidance offered in the WCAP, should this condition occur, is to develop a defensible inservice inspection program for these piping segments based on deterministic information, engineering insights and experience, and industry best practices. An inservice inspection program was identified that targeted each pipe size for each segment. This resulted in two inspection locations for one of the segments, three inspection locations for the second segment, and six inspection locations for the third segment. The three piping segments and the number of inspections for each of those segments are the same for both units.

Attachment 1

Table 5-1 SQN UNIT 1 STRUCTURAL ELEMENT SELECTION RESULTS AND COMPARISON TO ASME SECTION XI 1989 EDITION REQUIREMENTS								
System	Number of High Safety-Significant Segments (No. in Augmented Program)	RI-ISI Program High Safety-Significant Structural Elements[1]		ASME Section XI ISI Program 1989 Edition Examination Category Weld Selections[12]				Total Number of Segments Credited in Augmented Programs
		CLASS 1	CLASS 2	B-F	B-J	C-F-1	C-F-2	
AF	0	–	–	–	–	–	–	2
BD[9]	12 (8[5])	–	12[3]	–	–	–	–	12[5]
CH[10]	13 (3)	10+9[3]	2[6]	–	71	44	–	3
CI[9]	0	–	–	–	–	–	–	1[5]
CS	1 (0)	–	3+1[4]	–	–	16	–	0
FW[9]	8 (8[5])	–	8+8[4]	–	–	–	11	14[5]+2
MS[9]	0	–	1[8]	–	–	–	18	14[5]
RC[11]	17 (2)	11+8[7]+9[3]	–	22	73	–	–	2
RH	5 (0)	2	4+1[4]+4[8]	–	5	23	–	0
SI[10]	33 (4)	12+***13***[3]	12+***6***[3]+3[4]	–	110	60	–	4
SQ	0	–	–	–	–	–	–	0
Total	89	74	***65***	22	259	143	29	54

Changes to the above table from TVA's original submittal are shown in bold and italic. This information supersedes the information provided previously by TVA letter dated March 23, 2001.

Summary: Current ASME Section XI selects a total of 453[12] weld locations for non-destructive examination while the proposed RI-ISI program selects a total of 75 exam locations (***139-64*** visual exam locations), which results in a 83% reduction.

Notes:

1. ASME Section XI system pressure tests and VT-2 visual examinations shall continue to be performed for all ASME Code Class 1 and 2 systems.
2. All augmented programs continue.
3. VT-2 examination for entire segment (see Request for Relief 1-RI-ISI-2).
4. VT-2 examination for a portion of the segment (see Request for Relief 1-RI-ISI-2).
5. UT thickness only.
6. VT-2 examination for entire segment.
7. Eight examination locations added for defense-in-depth at the reactor vessel nozzle to safe-end pipe welds.
8. Five examination locations added for change in risk considerations.
9. Augmented programs for erosion-corrosion (including MIC) continue.

Notes (continued):

10. Augmented program for thermal stratification of base metal at socket weld areas continues.
11. Augmented program for stress corrosion cracking of draw bead welds continues.
12. Weld selection numbers are based on plant procedure 0-SI-DXI-000-114.2 revision 10 "ASME Section XI ISI/NDE Program Unit 1 and Unit 2".

Table 5-2
SQN UNIT 2
STRUCTURAL ELEMENT SELECTION
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS

System	Number of High Safety-Significant Segments (No. in Augmented Program)	RI-ISI Program High Safety-Significant Structural Elements[1]		ASME Section XI ISI Program 1989 Edition Examination Category Weld Selections[11]				Total Number of Segments Credited in Augmented Programs
		CLASS 1	CLASS 2	B-F	B-J	C-F-1	C-F-2	
AF	0	–	–	–	–	–	–	2
BD[9]	12 (8[5])	–	12[3]	–	–	–	–	12[5]
CH[10]	13 (3)	10+9[3]	2[6]	–	77	46	–	3
CI[9]	0	–	–	–	–	–	–	1[5]
CS	1 (0)	–	3+1[4]	–	–	17	–	0
FW[9]	8 (8[5])	–	8+8[4]	–	–	–	11	12[5]+4
MS[9]	0	–	–	–	–	–	18	14[5]
RC	17 (2)	11+8[7]+9[3]	–	22	65	–	–	2
RH	5 (0)	2	4+1[4]+4[8]	–	6	23	–	0
SI[10]	31 (4)	7+***13***[3]	12+6[3]+3[4]+ 2[3,8]	–	90	61	–	4
SQ	0	–	–	–	–	–	–	0
Total	87	69	66	22	238	147	29	54

Changes to the above table from TVA's original submittal are shown in bold and italic. This information supersedes the information provided previously by TVA letter dated March 23, 2001.

Summary: Current ASME Section XI selects a total of 436[11] weld locations for non-destructive examination while the proposed RI-ISI program selects a total of 69 exam locations (135-66 visual exam locations), which results in a 84% reduction.

Notes:

1. ASME Section XI system pressure tests and VT-2 visual examinations shall continue to be performed for all ASME Code Class 1 and 2 systems.
2. All augmented programs continue.
3. VT-2 examination for entire segment (see Request for Relief 2-RI-ISI-2).
4. VT-2 examination for a portion of the segment (see Request for Relief 2-RI-ISI-2).
5. UT thickness only.
6. VT-2 examination for entire segment.
7. Eight examination locations added for defense-in-depth at the reactor vessel nozzle to safe-end pipe welds.
8. Six examination locations added for change in risk considerations.
9. Augmented programs for erosion-corrosion (including MIC) continue.

Notes (continued):

10. Augmented program for thermal stratification of base metal at socket weld areas continues.
11. Weld selection numbers are based on plant procedure 0-SI-DXI-000-114.2 revision 10 "ASME Section XI ISI/NDE Program Unit 1 and Unit 2".