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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Subject: Beaver Valley Power Station, Unit No. 1 and No. 2
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
Risk-Informed Inservice Inspection Program Plans
ISI (Inservice Inspection) Program Relief Request

The FirstEnergy Nuclear Operating Company (FENOC) hereby requests to implement a Risk-Informed Inservice Inspection (RI-ISI) Program as an alternative to the current American Society for Mechanical Engineers (ASME) Section XI inservice inspection requirements for piping at Beaver Valley Power Station Unit 1 (BVPS-1) and Unit 2 (BVPS-2). Therefore, the proposed RI-ISI Program Plans in Attachments 1 and 2 are being submitted for NRC review and approval in accordance with 10 CFR 50.55a(a)(3)(i).

The RI-ISI Program Plans have been developed in accordance with the Westinghouse Owners Group Topical Report WCAP-14572, Revision 1-NP-A, "Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report," and WCAP-14572, Revision 1-NP-A, Supplement 1, "Westinghouse Structural Reliability and Risk Assessment (SRRA) Model for Piping Risk-Informed Inservice Inspection." This program clearly supports the conclusion that the proposed alternative provides an acceptable level of quality and safety as required by 10 CFR 50.55a(a)(3)(i).

It is requested that NRC approval be provided by February 1, 2003, to support implementation during the BVPS-1 Fifteenth Refueling Outage currently scheduled for March 2003. To assist in your review, a comparison of the postulated consequences (reference Table 3.3-1 of Attachments 1 and 2) between BVPS-1 and BVPS-2 is provided in Attachment 3.

If you have any questions concerning this matter, please contact Mr. Larry R. Freeland, Manager, Regulatory Affairs/Corrective Action at 724-682-5284.

Sincerely,

Mark Pearson for

Mark B. Bezilla

Attachments:

1) FirstEnergy Nuclear Operating Company, Beaver Valley Power Station Unit No. 1, Risk-Informed Inservice Inspection Piping Program Using the Westinghouse Owners Group (WOG) Methodology, Revision 0, June 2002

2) FirstEnergy Nuclear Operating Company, Beaver Valley Power Station Unit No. 2, Risk-Informed Inservice Inspection Piping Program Using the Westinghouse Owners Group (WOG) Methodology, Revision 0, June 2002

3) FirstEnergy Nuclear Operating Company, Beaver Valley Power Station Unit No. 1 and No. 2, Risk-Informed Inservice Inspection Piping Program, Comparison of BVPS-1 and BVPS-2 Postulated Consequences by System

c: Mr. D. S. Collins, Project Manager
Mr. D. M. Kern, Sr. Resident Inspector
Mr. H. J. Miller, NRC Region I Administrator

ATTACHMENT 1

FirstEnergy Nuclear Operating Company

Beaver Valley Power Station Unit No. 1

Risk-Informed Inservice Inspection Piping Program

Using the Westinghouse Owners Group (WOG) Methodology

Revision 0

June 2002

RISK-INFORMED INSERVICE INSPECTION PROGRAM PLAN

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1. INTRODUCTION/RELATION TO NRC REGULATORY GUIDE RG-1.174

1.1 Introduction

Inservice inspections (ISI) are currently performed on piping to the requirements of the ASME Boiler and Pressure Vessel Code Section XI, 1989 Edition as required by 10CFR50.55a. The unit is currently in the second inspection period of the third inspection interval as defined by the Code for Program B.

The objective of this submittal is to request a change to the ISI program plan for piping through the use of a risk-informed ISI program. The risk-informed process used in this submittal is described in Westinghouse Owners Group WCAP-14572, Revision 1-NP-A, "Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report," and WCAP-14572, Revision 1-NP-A, Supplement 1, "Westinghouse Structural Reliability and Risk Assessment (SRRA) Model for Piping Risk-Informed Inservice Inspection," (referred to as "the WCAP" for the remainder of this document)."

As a risk-informed application, this submittal meets the intent and principles of Nuclear Regulatory Commission (NRC) Regulatory Guide 1.174. Further information is provided in Section 3.10 relative to defense-in-depth.

1.2 PRA Quality

The Beaver Valley Power Station Unit 1 Level 1 and Level 2 probabilistic risk assessment (PRA) model, Version BV1REV2 dated June 30, 1998 was used to evaluate the consequences of pipe ruptures during operation of BVPS Unit 1 in Modes 1 and 2. The base core damage frequency (CDF) and base large, early release frequency (LERF) from this version of the PRA model are 8.52E-05/yr and 9.23E-07/yr, respectively.

The suggested schedule for PRA model updates are 3-year intervals. Each unit's PRA model update is also recommended to be staggered 18 months apart from the other unit, to avoid overlap in the update process between PRA models and impacted programs. The administrative guidance for this activity is contained in administrative procedures.

Based on past PRA model updates performed for the Beaver Valley Units (three on Unit 1), it was observed that most PRA model updates do not change significantly due to plant modifications and new failure data. To ensure that this remains valid, administrative procedures require that a PRA model be revised any time a plant modification increases the CDF by more than 20% above the baseline CDF value. The impacts of these plant modifications are documented and analyzed for any increases in the baseline CDF and LERF. To date no single modification has increased CDF by more than 3% and the accumulated change in CDF due to plant modifications since the last PRA model update at Unit 1 are about a 4% decrease. Additionally, keeping within the established Maintenance Rule performance criteria for risk significant Systems, Structures, and Components (SSCs) helps to ensure that the impact on CDF due to equipment unavailability and failures remains minimal. Therefore, the current Beaver Valley PRA models are meeting the intent of Regulatory Guide 1.174 in that they reflect the actual design, construction, operational practices and experiences as they relate to risk significant systems. In the past, the significant changes to the PRA models were typically due to removing conservatism of previous models (e.g., using best estimate analyses in place of design bases analyses) or by taking additional credit for backup components (e.g., using LHSI

pumps in-place of HHSI pumps during small break LOCAs). Other significant changes involve improved state-of-the-art knowledge on PRA issues. Furthermore, an evaluation based on Appendix B of the EPRI PSA Applications Guide, was performed to confirm that the PRA conforms to the industry state-of-the-art with respect to completeness of coverage of potential scenarios.

The PRA model has been extensively reviewed including internal multi-disciplined reviews during the IPE process, and internal and external PRA consultant reviews during the PRA model updates.

During the NRC's review of the Individual Plant Evaluation (IPE), concerns were identified regarding the limited consideration of pre-initiator human actions. The NRC noted that the Human Reliability Analysis could have been strengthened by the use of a reasonably rigorous process to identify potential pre-initiator human error contributions to system unavailability. System unavailability has been monitored as part of implementation of the Maintenance Rule, including any system unavailability due to human errors. The plant specific data collected for system unavailability was then used in the PRA model updates performed since the initial IPE submittal. To identify pre-initiator human error contributions to system unavailability, possible misalignments that could reasonably occur on standby systems were postulated and the impact on top event logic models and minimal cutsets was determined. The probability that the system/train is unavailable due to a misalignment event was calculated based on generic failure rates for errors of omission, the frequency of tests and maintenance on standby systems, and the duration of the misalignment. System unavailability resulting from human errors is therefore accounted for in the current models.

2. PROPOSED ALTERNATIVE TO ISI PROGRAM

2.1 ASME Section XI

ASME Section XI Categories B-F, B-J, C-F-1 and C-F-2 currently contain the requirements for examining via non-destructive examination (NDE) for Class 1 and 2 piping components. The proposed program is limited to ASME Class 1 and Class 2 piping, including piping currently exempt from NDE requirements. The alternative risk-informed inservice inspection (RI-ISI) program for piping is described in the WCAP. The RI-ISI program will be substituted for the current examination program on piping in accordance with 10 CFR 50.55(a)(3)(i) by implementing an alternate methodology that provides an acceptable level of quality and safety. Other examination categories will be unaffected. The WCAP provides the requirements defining the relationship between the risk-informed examination program and the remaining unaffected portions of ASME Section XI.

2.2 Augmented Programs

The augmented inspection programs remain unchanged as a result of the RI-ISI program.

3. RISK-INFORMED ISI PROCESSES

The processes used to develop the RI-ISI program are consistent with the methodology described in the WCAP.

The process that is being applied, involves the following steps:

- Scope Definition
- Segment Definition
- Consequence Evaluation
- Failure Assessment
- Risk Evaluation
- Expert Panel Categorization
- Structural Element/NDE Selection
- Implement Program
- Feedback Loop

Deviations

As part of the risk evaluation described in Section 3.5, the uncertainty analysis as described on page 125 of the WCAP was performed and is now included as part of the base process.

Structural Element/NDE Selection: Perdue

Three segments QS-001, QS-002, and QS-042 were considered outside of the applicability of the Perdue model (see the WCAP for Perdue description). The safety significance of these 3 segments, as determined by the quantitative criteria, is high safety significance as the associated risk reduction worth (RRW) values are equal to or higher than 1.005. The expert panel categorized these 3 segments as high safety significant based on consequences of failures and risk evaluation results. Perdue evaluation is not required for segment QS-042 since it contains only 1 weld. The failure of segments QS-001 and QS-002 in the event of a catastrophic accident can lead to loss of the Refueling Water Storage Tank (RWST) inventory and they are unisolable from the RWST.

The Perdue model uses failure probability results from the Structural Reliability and Risk Assessment (SRRA) evaluation to determine if there is a 95% confidence that the probability of the leak rate per year per lot is less than the target leak rate per year per lot. When the probability of a flaw (10% through-wall crack) at the present age of the plant is close to 1.0, and the failure probabilities are of sufficient magnitude, the confidence does not meet the 95% acceptance criteria. The probability of a flaw at the plant's present age has a value close to 1.0 for these thin-walled (schedule 10S) piping segments. Based on the original design classification, each weld in these piping segments may not have received a construction radiograph. The SRRA input therefore conservatively considered the existence of a flaw in the calculation of the failure probability. Therefore, a very small conditional probability of a leak/year/weld is required to obtain an acceptable (>95%) confidence that the calculated leak rate will be less than the target leak rate.

Application of the overall process (i.e., risk evaluation, SRRA, and Perdue model) indicates that 100% of the welds in the segments of interest need to be examined in the proposed risk-informed ISI program. This result is judged to be inappropriate by the engineering team for these segments for the following reasons:

- The piping segments operate at low temperatures (<45°F to seasonal) and low pressures (<25 psi).
- The piping is typically not in service except during periodic testing, is under pressure only due to RWST static head, and in the event that the quench spray must be used to mitigate an accident.
- The piping is constructed of 304SS, which is a ductile material with high fracture toughness values.
- Leaks have not been discovered in these piping segments in more than 25 years of operation.
- There are no known active degradation mechanisms existing within these segments.

The engineering team reviewed the Perdue model applicability for segments QS-001 and QS-002. Based on this review, it has been determined that the Perdue model should not be used to establish a statistically relevant inspection sample size to verify the condition of the piping. The following summarizes this rationale:

- Segments QS-001 and QS-002 were fabricated, installed and tested in accordance with ANSI B31.1-1967. This piping was classified as Piping Class III (Q3) per the UFSAR. Therefore, a construction code radiograph was not required for the piping welds within these segments. However, surface examinations were required and performed. Using the optional guidelines of Regulatory Guide 1.26, the piping was subsequently upgraded by BV1 to ASME Code Class 2 for inservice inspection purposes.
- Given that pre-service examination using volumetric examination methods was not performed during original construction, the existence of a flaw was assumed for SRRA calculations subsequently used to support the risk evaluation and the Perdue model.
- Per page 171 of the WCAP, the Perdue model is based on the probability of a flaw existing (at the current age of the plant) that exceeds an unacceptable flaw defined by ASME Section XI Code. The unacceptable flaw has been defined as a/t>0.10, based on general acceptance standards that are appropriate for reactor piping operating at higher temperatures, pressures, and expected operating and design basis loadings. This is conservative for QS piping.
- When the large flaw size distribution is combined with the above Perdue model assumption (particularly since thin-wall piping is being evaluated), an unreasonable 100% sample size result is determined.
- The a/t>0.10 Perdue model assumption is inappropriate for the piping segments of interest. The operating temperatures and pressures for these thin-walled piping segments are <150°F and <100 psi, respectively. Given these conditions, along with the fact that the piping is constructed of stainless steel material that is ductile and has an inherently high fracture toughness, piping fracture evaluation experience to date indicates that the unacceptable flaw size would at least have an a/t>0.50 using fracture evaluation methods defined in ASME Section XI.
- If the Perdue model could account for this value, the probability of having a flaw exceeding this value at the current age of the plant would be significantly reduced. A highly reliable piping system would be demonstrated that would reflect a conclusion consistent with the engineering judgment discussed above.

Thus, the statement on page 184 of the WCAP, “Other situations may exist that warrant considerations beyond the above guidance” - is exercised in the selection of actual inspection locations. The recommended number of examinations for these segments is one each. BV1 currently performs examinations on both segments QS-001 and QS-002.

Structural Element/NDE Selection; Change In Risk

The change in risk methodology described in Section 3.10 deviated from the methodology for segments located inside containment and segments that interface with the Reactor Coolant System such that radiation monitors and sump level will detect a leak. The Reactor Coolant System was defined to be the Class 1 primary loop pressure boundary piping. Beaver Valley Power Station Unit 1 capability to detect a leak within the RCS is defined to be 1 gpm per Tech Spec documentation. 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.

3.1 Scope of Program

The scope of this program is ASME Class 1 and 2 piping, including piping exempt from current requirements. The piping systems included in the risk-informed ISI program are provided in Table 3.1-1.

Table 3.1-1: System Selection and Segment Definition for Beaver Valley Power Station 1 Class 1 and 2 Piping

System Description	PRA	Section XI	Number of Segments
Steam Generator Blowdown System (BD)	Yes	No	27
Chemical and Volume Control System (CH)	Yes	Yes	149[1]
Containment Isolation System (CI)	Yes	No	151
Reactor Plant Drains and Vents Systems (DV)	Yes	Yes	7
Steam Generator Feedwater System (FW)	Yes	Yes	21
Hydrogen Control System (HY)	Yes	No	32
Main Steam System (MS)	Yes	Yes	48
Quench Spray System (QS)	Yes	Yes	48
Reactor Coolant System (RC)	Yes	Yes	81
Residual Heat Removal System (RH)	Yes	Yes	38
Recirculation Spray System (RS)	Yes	Yes	37
Safety Injection System (SI)	Yes	Yes	154
Sampling System (SS)	Yes	No	44
Total			837

Note: 1. Three “Not Used” segments under the CH identifier are included in the segment count.

3.2 Segment Definitions

Once the systems to be included in the program are determined, the piping for these systems is divided into segments.

The number of pipe segments defined for the Class 1 and 2 piping (13 systems) is summarized in Table 3.1-1. The Valve Operating Number Diagrams and Piping Flow Diagrams were used to define the segments.

3.3 Consequence Evaluation

The consequences of pressure boundary failures are measured in terms of core damage and large early release. The impact on these measures due to both direct and indirect effects was considered. Table 3.3-1 summarizes the postulated consequences for each system.

Table 3.3-1

Summary of Postulated Consequences by System

System	Summary of Consequences
Steam Generator Blowdown System (BD)	Direct effects: Reactor Trip (RT) and Partial Loss of Main Feedwater (PLMFW) Initiating Events. Loss of Auxiliary Feedwater, Dedicated Auxiliary Feedwater and Main Feedwater to Steam Generators. Loss of the containment pressure boundary. Indirect effects: None
Chemical and Volume Control System (CH)	Direct effects: Reactor Trip (RT), Small or Medium LOCA Initiating Events. The following consequences would occur due to pipe failures in various locations within the CH System. • Loss of High Head and Low Head Safety Injection • Loss of recirculation • Loss of seal injection to one or more RCP seals • Loss of one or both charging trains • Loss of Letdown • Loss of normal and emergency boration • Loss of Refueling Water Storage Tank inventory outside of containment • Loss of Containment Sump Inventory outside of containment • Loss of the containment pressure boundary. Indirect effects: Indirect effects for jet impingement/spray were identified that disabled the alternate charging flow path, the alternate train of high head injection/recirculation, or a RCP seal injection flow path.

Table 3.3-1 Summary of Postulated Consequences by System	
System	Summary of Consequences
Containment Isolation System (CI)	Direct effects: Loss of Primary Component Cooling, Containment Instrumentation Air, and Station Instrument Air Initiating Events. Loss of RCP thermal barrier and motor cooling. Loss of cooling to the RHR heat exchangers. Loss of chilled water system. Loss of river water flow to recirculation spray heat exchanger. Loss of the containment pressure boundary. Indirect effects: Indirect effects for spray were identified that would disable a charging flow control valve and a reactor system drain train.
Reactor Plant Drains and Vents Systems (DV)	Direct effects: Loss of the containment pressure boundary. Indirect effects: None
Steam Generator Feedwater System (FW)	Direct effects: Reactor Trip (RT), Partial Loss of Main Feedwater (PLMFW), and Total Loss of Main Feedwater (TLMFW) Initiating Events. Loss of main, auxiliary, or dedicated auxiliary feedwater to one or more steam generators. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.
Hydrogen Control System (HY)	Direct effects: Loss of the containment pressure boundary. Indirect effects: None
Main Steam System (MS)	Direct effects: Steam Line Break Inside Containment (SLBI), Steam Line Break Outside Containment (SLBD), and Steam Line Break in Common RHR Valve Line (SLBC) Initiating Events. Loss of Main Feedwater to all steam generators due to MFW Pump trip on SI signal. Loss of Main Feedwater, Auxiliary Feedwater and Dedicated Auxiliary Feedwater to faulted steam generator. Failure of one or more of the steam supply paths to the Turbine Driven Auxiliary Feedwater Pump. Disabled atmospheric steam dump valves on the faulted steam generators. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.

Table 3.3-1 Summary of Postulated Consequences by System	
System	Summary of Consequences
Quench Spray System (QS)	Direct effects: Loss of RWST inventory outside containment. Loss of one or both trains of QS, LHSI / HHSI injection and recirculation. Loss of the containment pressure boundary. Indirect effects: Quench Spray impacts are addressed as part of the direct effects assessment.
Reactor Coolant System (RC)	Direct effects: Depending upon location and size, segment failure will result in either a small, medium, or large break LOCA. In addition, failures of other functions such as hot or cold leg injection or recirculation, loss of RHR, loss of pressurizer spray, and loss of letdown or charging could occur. Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RC piping failures were evaluated and mitigated as part of design basis activities.
Residual Heat Removal System (RH)	Direct effects: Small, medium, or large LOCA Initiating Events. Depending upon location, segment failure (without operator action) results in a loss of one or more of the following functions: • Loss of RHR • Loss of HHSI and LHSI hot leg recirculation • Loss of accumulator injection Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RH piping failures were evaluated and mitigated as part of design basis activities.
Recirculation Spray System (RS)	Direct effects: Loss of containment sump inventory due to the failure outside containment. Failure will eventually lead to failure of all RS and all HHSI/LHSI recirculation. Loss of containment and decay heat removal. Loss of the containment pressure boundary. Indirect effects: None

Table 3.3-1 Summary of Postulated Consequences by System	
System	Summary of Consequences
Safety Injection System (SI)	Direct effects: Reactor Trip (RT); Small, Medium or Large LOCA Initiating Events. Loss of the containment pressure boundary. Depending upon location, segment failure can result in a loss of one or more of the following functions: • Loss of accumulator injection • High Pressure Injection • High Pressure Recirculation • Low Pressure Injection • Low Pressure Recirculation • Loss of RWST inventory outside containment, LHSI. HHSI, QS, and RS Pumps for Injection and Recirculation Indirect effects: Indirect effects for spray were identified that would disable a charging system valve.
Sampling System (SS)	Direct effects: Reactor Trip (RT) Initiating Event. Loss of affected accumulator. Loss of the containment pressure boundary. Indirect effects: None

3.4 Failure Assessment

Failure estimates were generated utilizing industry failure history, plant specific failure history and other relevant information. An engineering team was established having access to expertise from ISI, NDE, materials, stress analysis and system engineering. 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 Supplement 1 of the WCAP. The WinSRRA code was used to calculate failure probabilities for the failure modes, materials, degradation mechanisms, input variables and uncertainties it was programmed to consider as discussed in Supplement 1 of the WCAP. All the piping configurations included in the RI-ISI program could be adequately modeled using the code.

The engineering team assessed industry and plant experience, plant layout, materials, and operating conditions to identify the potential failure mechanisms and causes. Information was gathered from various sources by the engineering team to provide input for the SRRA model. BV1 snubber failure history was reviewed to identify any potential effects that could increase piping failure probability.

Consideration was also given to whether a segment was addressed by either a plant stress corrosion cracking or erosion corrosion augmented program. This information was used to determine which failure probability was used in the risk-informed ISI process. The effects of ISI on existing augmented programs are included in the risk evaluation used to assist in categorizing the segments as described on page 105 of the WCAP. The failure probabilities used in the risk-informed process are documented and maintained in the plant records.

Table 3.4-1 summarizes the failure probability estimates for the dominant potential failure mechanisms by system. Table 3.4-1 also describes why the degradation mechanisms could occur at various locations within the system. Full break cases may be included but only when pipe whip is of concern. All instances where pipe whip would be a concern were addressed as part of the original plant design for BV1.

Table 3.4-1 Failure Probability Estimates (without ISI)				
System	Dominant Potential Degradation Mechanism(s)/Combinations(s)	Failure Probability Range at 40 Years with No ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
BD	Erosion/Corrosion, Thermal Fatigue	6.81E-06 – 4.93E-05	SYS 1.70E-09 - 9.71E-06	System is included in the current Flow Accelerated Corrosion Augmented Inspection program.
CH	Thermal Fatigue Thermal & Vibratory Fatigue	3.46E-08 – 2.17E-04 6.38E-05 – 5.50E-03	SLOCA 1.42E-09 - 5.06E-05 SYS 9.03E-11 - 7.30E-05 SLOCA 1.76E-08 - 3.65E-03 SYS 6.99E-09 - 3.65E-03	 Vibration occurs near the orifices in various locations throughout the system. Downstream of the charging pumps and letdown heat exchanger are the critical orifice locations. Vibration occurs on small branch connections near pumps.
CI	Erosion/Corrosion, Thermal Fatigue Thermal Fatigue	1.10E-07 – 4.13E-07 1.09E-07 – 4.05E-05	SYS 1.32E-10 - 5.81E-09 SYS 2.85E-11 - 1.22E-05	Microbiological mechanisms were identified in the river water portions of the piping lines.
DV	Thermal Fatigue	4.90E-7 – 1.97E-5	SYS 1.34E-10 - 4.06E-07	
FW	Erosion/Corrosion, Thermal Fatigue	1.52E-08 – 1.84E-06	SYS 1.18E-12 - 1.76E-07	System is included in the current Flow Accelerated Corrosion Augmented Inspection program.
HY	Thermal Fatigue	2.67E-07 – 1.05E-05	SYS 2.67E-07 - 1.05E-05	Gas segments where in all cases a small leak would disable the system function.
MS	Erosion/Corrosion, Thermal Fatigue	2.79E-07 - 4.63E - 04	SYS 2.51E-10 - 5.63E-05	System is included in the current Flow Accelerated Corrosion Augmented Inspection program.
QS	Thermal Fatigue Vibrational Fatigue	5.40E-07 – 2.61E-04 4.33E-05 – 3.21E-04	SYS 5.95E-11 - 3.06E-05 SYS 8.05E-09 - 4.43E-04	 Vibration occurs on small branch connections near pumps.

Table 3.4-1 Failure Probability Estimates (without ISI)				
System	Dominant Potential Degradation Mechanism(s)/Combinations(s)	Failure Probability Range at 40 Years with No ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
RC	Stress Corrosion/Cracking, Thermal Fatigue	4.97E-10 – 1.88E-05	LLOCA 1.53E-12 - 3.67E-06 MLOCA 2.04E-12 - 3.67E-06 SLOCA 1.02E-11 - 4.77E-06 SYS 1.32E-11 - 9.33E-06	
	Stress Corrosion /Cracking, Thermal Fatigue, Vibrational Fatigue, Striping/Stratification	2.03E-06 – 1.25E-05	LLOCA 5.45E-10 - 8.72E-06 MLOCA 5.94E-10 - 8.95E-06 SLOCA 7.37E-10 - 8.93E-06 SYS 1.11E-09 - 1.01E-05	Industry history identifies thermal striping or stratification occurs in the pressurizer surge line. Temperature monitoring is on going but no evidence of fatigue or structural concerns have been noted.
	Water Hammer	1.73E-07 – 1.73E-07	SYS 3.73E-10 - 4.44E-10	
RH	Thermal Fatigue	1.14E-07 – 8.70E-05	LLOCA 6.00E-10 - 4.00E-07 MLOCA 6.06E-10 - 4.10E-07 SLOCA 6.27E-10 - 4.10E-07 SYS 4.33E-16 - 7.22E-05	
	Thermal Fatigue, Vibrational Fatigue	3.01E-05 – 3.61E-03	SYS 5.05E-10 - 2.50E-03	Vibration occurs on small branch connections near pumps.
RS	Thermal Fatigue	1.07E-05 - 1.53E-04	SYS 6.77E-11 - 8.34E-05	
	Thermal Fatigue, Vibrational Fatigue	2.92E-05 - 1.20E-04	SYS 4.74E-10 - 4.04E-05	Vibration occurs on small branch connections near pumps.
SI	Thermal Fatigue	8.01E-11 – 3.35E-04	LLOCA 2.09E-08 - 1.15E-05 MLOCA 6.25E-10 - 2.00E-05 SLOCA 2.63E-10 - 1.01E-04 SYS 3.65E-13 - 3.34E-05	The potential for thermal striping or stratification exists on small branch lines containing check valves connected to the main loop.
SS	Thermal Fatigue	7.89E-06 – 3.29E-05	SYS 3.52E-10 - 2.20E-05	

Notes:
* - Disabling leak rate – LLOCA, MLOCA, SLOCA, and SYS (system disabling leak).

3.5 Risk Evaluation

Each piping segment within the scope of the program was evaluated to determine its core damage frequency (CDF) and large, early release frequency (LERF) due to the postulated piping failure. Calculations were also performed with and without operator action.

Once this evaluation is completed, the total pressure boundary core damage frequency and large early release frequency are calculated by summing across the segments for each system.

The uncertainty analysis as described on page 125 of the WCAP was performed and is now included as part of the base process. The results of these calculations are presented in Table 3.5-1. The core damage frequency due to piping failure without operator action is 7.62E-07/year, and with operator action is 5.30E-07/year. The large early release frequency due to piping failure without operator action is 1.40E-08/year, and with operator action is 1.13E-08/year.

To assess safety significance, the risk reduction worth (RRW) and risk achievement worth (RAW) were calculated for each piping segment.

Table 3.5-1
Number of Segments and Piping Risk Contribution by System (without ISI)

System	# of Segments	CDF without Operator Action (/yr)	CDF with Operator Action (/yr)	LERF without Operator Action (/yr)	LERF with Operator Action (/yr)
BD	27	2.67E-10	1.82E-12	3.89E-14	3.74E-14
CH	149	2.17E-07	8.19E-08	2.15E-09	5.68E-10
CI	151	1.26E-10	1.26E-10	1.01E-11	1.01E-11
DV	7	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FW	21	4.23E-11	7.59E-13	6.26E-12	1.54E-14
HY	32	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MS	48	1.98E-11	1.99E-11	9.07E-13	9.28E-13
QS	48	7.84E-10	2.69E-13	9.55E-12	5.01E-13
RC	81	1.02E-07	9.97E-08	1.59E-09	1.56E-09
RH	38	8.81E-10	8.81E-10	1.39E-11	1.39E-11
RS	37	2.27E-09	2.24E-09	2.28E-09	2.28E-09
SI	154	4.39E-07	3.46E-07	7.89E-09	6.89E-09
SS	44	1.07E-10	3.06E-15	7.64E-13	2.30E-17
Total	837	7.62E-07	5.30E-07	1.40E-08	1.13E-08

3.6 Expert Panel Categorization

The final safety determination, (i.e., high and low safety significance), of each piping segment was made by the expert panel using both probabilistic and deterministic insights. The expert panel was comprised of personnel who have expertise in the following fields: probabilistic safety assessment, inservice examination, nondestructive examination, stress and material considerations, plant operations, plant and industry maintenance, repair and failure history, system design and operation, and SRRA methods including uncertainty. Members associated with the Maintenance Rule were used to ensure consistency with the other PRA applications.

The expert panel had the following positions represented by the permanent member at all times during the expert panel meeting.

- Probabilistic Risk Assessment (PRA Supervisor)
- Operations (Nuclear Operations (ANSS))
- Inservice Inspection and Nondestructive Examination (NDE Inspection)
- Plant & Industry Maintenance (Maintenance Engineering/Maintenance Rule)
- Repair, and Failure History (System Engineer)
- System Design and Operation (System Engineer)
- Licensing and Safety Analysis (Licensing/Safety Engineer)
- Materials (Materials Engineering)
- Stress (Structural Engineering)

A minimum of 4 members or alternates filling the above positions constituted a quorum. This core team of panel members was supplemented by other experts, including an ISI Engineer and PRA Engineer, as required for the piping system under evaluation.

FirstEnergy Nuclear Operating Company appointed the expert panel chairperson. The chairperson conducted and ruled on the proceedings of the meetings.

Members and alternates received training and indoctrination in the risk-informed inservice inspection selection process. They were indoctrinated in the application of risk analysis techniques for ISI. These techniques included risk importance measures, threshold values, failure probability models, failure mode assessments, PRA modeling limitations and the use of expert judgment. Training documentation is maintained with the expert panel's records.

Worksheets were provided to the panel on each system for each piping segment, containing information pertinent to the panel's selection process. This information, in conjunction with each panel member's own expertise and other documents as appropriate, were used to determine the safety significance of each piping segment.

A consensus process was used by the expert panel. Consensus was defined as unanimous for this initial application of the RI-ISI methodology. The chairperson permitted active discussion during the proceedings and appropriate time for deliberation.

Minutes of each meeting were generated. The minutes included the names of members and alternates in attendance and whether a quorum was present. The minutes contained relevant discussion summaries and the results of membership voting. These minutes are available as program records.

3.7 Identification of High Safety Significant Segments

The number of high safety significant segments (HSS) for each system, as determined by the expert panel, is shown in Table 3.7-1 along with a summary of the risk evaluation identification of high safety significant segments.

Table 3.7-1
Summary of Risk Evaluation and Expert Panel Categorization Results

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)
BD	0	0	27	0	27	27 (0)
CH	26	18	105	7	1	28 (28)
CI	0	3	148	0	0	0 (0)
DV	0	0	7	0	0	0 (0)
FW	0	0	21	0	21	21 (0)
HY	0	0	32	0	0	0 (0)
MS	0	0	48	0	48	48 (8)
QS	0	2	46	0	3	3 (3)
RC	14	16	51	6	0	20 (20)
RH	0	1	37	1	18	19 (19)
RS	10	2	25	0	0	10 (10)
SI	34	42	78	7	1	30 (30)
SS	0	0	44	0	0	0 (0)
TOTAL	84	84	669	21	119	206 (118)

3.8 Structural Element and NDE Selection

The structural elements in the high safety significant piping segments were selected for inspection and appropriate non-destructive examination (NDE) methods were defined.

The initial program being submitted addresses the HSS piping components placed in regions 1 and 2 of Figure 3.7-1 in the WCAP. Segments considered as “high failure importance” (Region 1) were identified as all segments being affected by an active failure mechanism or analyzed to be highly susceptible to a failure mechanism (probability of large leak at 40 years generally exceeds 1E-04). Region 3 piping components, which are low safety significant, are to be considered in an Owner Defined Program and are not considered part of the program requiring

approval. Region 1, 2, 3 and 4 piping components will continue to receive Code required pressure testing, as part of the current ASME Section XI program. For the 837 piping segments that were evaluated in the RI-ISI program, Region 1 contains 9 segments, Region 2 contains 109 segments, Region 3 contains 95 segments, and Region 4 contains 621 segments. Three segment identifiers in the CH system sequence were not used to identify a piping segment but were included in the segment counts. These segments were not included in the region counts.

The number of locations to be inspected in a HSS segment was determined using a Westinghouse statistical (Perdue) model as described in section 3.7 of the WCAP. All of the HSS piping segments in Region 1 and 106 of the HSS piping segments in Region 2 were evaluated using the Perdue model. The 3 segments that were not evaluated using the Perdue model included 1 segment with only 1 weld for which no Perdue evaluation is required and 2 segments that were outside of the model as discussed in Section 3 of this submittal. For these 3 segments, the guidance in Section 3.7.3 of the WCAP was followed.

Table 4.1-1 in the WCAP was used as guidance in determining the examination requirements for the HSS piping segments. VT-2 visual examinations are scheduled in accordance with the station's pressure test program that remains unaffected by the risk-informed inspection program.

Additional Examinations

Since the risk-informed inspection program will require examinations on a large number of elements constructed to lesser pre-service inspection requirements, the program in all cases will determine through an engineering evaluation the root cause of any unacceptable flaw or relevant condition found during examination. The evaluation will include the applicable service conditions and degradation mechanisms to establish that the element(s) will still perform their intended safety function during subsequent operation. Elements not meeting this requirement will be repaired or replaced.

The evaluation will include whether other elements on the segment or segments are subject to the same root cause and degradation mechanism. Additional examinations will be performed on these elements up to a number equivalent to the number of elements initially required to be examined on the segment or segments. If unacceptable flaws or relevant conditions are again found similar to the initial problem, the remaining elements identified as susceptible will be examined. No additional examinations will be performed if there are no additional elements identified as being susceptible to the same service related root cause conditions or degradation mechanism.

3.9 Program Relief Requests

An attempt has been made to provide a minimum of >90% coverage (per Code Case N-460) when performing the risk-informed examinations. However, not all limitations will be known until the examination is performed, since some locations will be examined for the first time by the specified techniques.

When the examination does not meet >90% coverage, the process outlined in Section 4.0 of the WCAP will be followed.

3.10 Change in Risk

The risk-informed ISI program has been done in accordance with Regulatory Guide 1.174, and the risk from implementation of this program is expected to slightly decrease when compared to that estimated from current requirements.

The change in risk calculations were performed according to all the guidelines provided on page 213 of the WCAP. A comparison between the proposed RI-ISI program and the current ASME Section XI ISI program was made to evaluate the change in risk. The approach evaluated the change in risk with the inclusion of the probability of detection as determined by the SRRA model. All four criteria for accepting the results discussed on page 214 and 215 in the WCAP were met (or adjustments were made to add segments until the criteria were met). This evaluation resulted in the identification of 4 piping segments for which examinations are now required (2 for SI and 2 for RC).

The change in risk methodology deviated from the methodology for segments located inside containment and that interface with the Reactor Coolant System such that radiation monitors and sump level will detect a leak. The Reactor Coolant System was defined to be the Class 1 primary loop pressure boundary piping. Beaver Valley Power Station Unit 1 capability to detect a leak within the Reactor Coolant System is defined to be 1 gpm per Tech Spec documentation. For these segments, the failure probability “with ISI” for those being examined by NDE and “without ISI” for those not being examined is used along with credit for leak detection.

The results from the risk comparison are shown in Table 3.10-1. As seen from the table, the RI-ISI program reduces the risk associated with piping CDF/LERF slightly more than the current Section XI program while reducing the number of examinations. Table 3.10-1 also includes the systems that are the main contributors to the risk reduction in moving from the current program to the RI-ISI program. The primary basis for this risk reduction is that examinations are now being placed on piping segments that are high safety significant and which are not inspected by NDE in the current ASME Section XI ISI program.

<u>Defense-In-Depth</u>

The reactor coolant piping will continue to receive a system pressure test and visual VT-2 examination as currently required by the ASME XI Code. Larger reactor coolant loop piping segments were retained in the program for “defense-in-depth” considerations. All reactor vessel dissimilar metal welds were selected for examination.

Table 3.10-1 COMPARISON OF CDF/LERF FOR CURRENT SECTION XI AND RISK-INFORMED ISI PROGRAMS AND THE SYSTEMS WHICH CONTRIBUTED SIGNIFICANTLY TO THE CHANGE		
Case (Systems Contributing to Change)	Current Section XI	Risk-Informed
CDF No Operator Action	3.25E-07	2.99E-07
• BD	2.67E-10	2.67E-10
• CH	1.74E-07	1.53E-07
• CI	1.26E-10	1.26E-10
• FW	4.23E-11	4.23E-11
• MS	1.98E-11	1.98E-11
• QS	9.83E-11	7.84E-10
• RC	3.07E-08	3.06E-08
• RH	1.81E-11	1.81E-11
• RS	2.25E-09	1.53E-10
• SI	1.17E-07	1.14E-07
• SS	1.07E-10	1.07E-10
CDF with Operator Action	1.53E-07	1.24E-07
• CH	6.19E-08	3.81E-08
• CI	1.26E-10	1.26E-10
• MS	1.99E-11	1.99E-11
• RC	3.06E-08	3.04E-08
• RH	1.81E-11	1.81E-11
• RS	2.24E-09	1.29E-10
• SI	5.81E-08	5.54E-08

Table 3.10-1 (continued) COMPARISON OF CDF/LERF FOR CURRENT SECTION XI AND RISK-INFORMED ISI PROGRAMS AND THE SYSTEMS WHICH CONTRIBUTED SIGNIFICANTLY TO THE CHANGE		
Case (Systems Contributing to Change)	Current Section XI	Risk-Informed
LERF No Operator Action	5.91E-09	3.38E-09
• CH	1.62E-09	1.36E-09
• CI	1.01E-11	1.01E-11
• FW	6.26E-12	6.26E-12
• MS	9.07E-13	9.07E-13
• QS	1.80E-12	9.55E-12
• RC	4.81E-10	4.81E-10
• RH	2.84E-13	2.84E-13
• RS	2.28E-09	2.45E-11
• SI	1.52E-09	1.49E-09
• SS	7.64E-13	7.64E-13
LERF with Operator Action	4.01E-09	1.58E-09
• CH	3.55E-10	1.98E-10
• CI	1.01E-11	1.01E-11
• MS	9.28E-13	9.28E-13
• QS	4.69E-13	5.01E-13
• RC	4.78E-10	4.77E-10
• RH	2.84E-13	2.84E-13
• RS	2.28E-09	2.41E-11
• SI	8.75E-10	8.71E-10

4. IMPLEMENTATION AND MONITORING PROGRAM

Upon approval of the RI-ISI program, procedures that comply with the guidelines described in the WCAP will be prepared to implement and monitor the program. The new program will be integrated into the existing ASME Section XI interval. No changes to the Updated Final Safety Analysis Report are necessary for program implementation.

The applicable aspects of the Code not affected by this change would be retained, such as examination methods, acceptance guidelines, pressure testing, corrective measures, documentation requirements, and quality control requirements. Existing ASME Section XI program-implementing procedures would be retained and would be modified to address the RI-ISI process, as appropriate. Additionally the procedures will be modified to include the high safety significant locations in the program requirements regardless of their current ASME class.

The proposed monitoring and corrective action program will contain the following elements**:**

A. Identify
B. Characterize
C. (1) Evaluate, determine the cause and extent of the condition identified
   (2) Evaluate, develop a corrective action plan or plans
D. Decide
E. Implement
F. Monitor
G. Trend

The RI-ISI program is a living program requiring feedback of new relevant information to ensure the appropriate identification of high safety significant piping locations. As a minimum, risk ranking of piping segments will be reviewed and adjusted on an ASME period basis. Significant changes may require more frequent adjustment as directed by NRC bulletin or Generic Letter requirements, or by plant specific feedback.

5. PROPOSED ISI PROGRAM PLAN CHANGE

A comparison between the RI-ISI program and the current ASME Section XI program requirements for piping is given in Table 5-1. An identification of piping segments that are part of plant augmented programs is also included in Table 5-1.

The plant will be performing examinations on elements not currently required by ASME Section XI. An example of these additional examinations is provided below.

- The ASME Section XI Code does not require examination of piping less than 3/8-inch wall thickness on Class 2 piping greater than 4-inch nominal pipe size (NPS). The welds are counted for percentage requirements, but not examined by NDE. The RI-ISI program will require examination in this population of welds. Examples where the risk informed process required examination and the Code did not are the suction lines to the charging pumps connected to the emergency boration flow path.

The initial program will be started in the inspection period current at the time of program approval. For example, the second (of three) inspection periods of the current 10-year inspection interval for BV1 ends on December 2, 2004. If the program is approved such that a refueling outage remains in the second period, 66% of the required RI-ISI examinations will be performed by the end of the current inspection interval.

Table 5-1

STRUCTURAL ELEMENT SELECTION (SES)
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS

System	High Safety Significant Segments (No. of HSS in Augmented Program / Total No. of Segments in Aug. Program)	Degradation Mechanism(s)	Safety Class	ASME Code Exam Category	Total Weld Count (Welds requiring Volumetric (Vol) and Surface (Sur))		ASME XI Program Examinations		RI-ISI[a]		
					Vol & Sur	Sur only	Vol & Sur	Sur only	SES Matrix Region	No. of Aug. Program Segments	Number of Exam Locations
BD	0 (0/27)	FAC/TF	Class 2	N/A	0	0	0	0	3	27[c]	0
CH	28 (0/0)	TF/VF, TF	Class 1	B-J	25	287	7	64	1A, 2, 3, 4	0	0
			Class 2	C-F-1	317	303	17	18		0	8 + 19[b] + 2[e]
CI	0 (0/0)	FAC/TF, TF	Class 2	N/A	0	0	0	0	4	0	0
DV	0 (0/0)	TF	Class 1	B-J	0	106	0	27	4	0	0
FW	0 (0/21)	FAC/TF	Class 2	C-F-2	62	0	14	0	3	21[c]	0
HY	0 (0/0)	TF	Class 2	N/A	0	0	0	0	4	0	0
MS	8 (8/48)	FAC/TF	Class 2	C-F-2	106	0	23	0	1B, 3	48[c]	8[f]
QS	3 (0/0)	TF, VF	Class 2	C-F-1	157	50	12	4	2, 3, 4	0	3
RC	20 (0/0)	SCC/TF, SCC/TF/VF/SS, WH	Class 1	B-F	18	0	18	0	2, 4	0	7
			Class 1	B-J	207	181	55	53		0	13+ 2[d]
RH	19 (0/0)	TF, TF/VF	Class 1	B-J	26	0	6	0	2, 3, 4	0	2
			Class 2	C-F-1	177	0	14	0		0	15 + 2[b]
RS	10 (0/0)	TF, TF/VF	Class 2	C-F-1	84	14	7	2	2, 4	0	10
SI	30 (0/0)	TF	Class 1	B-J	193	108	43	31	1A, 1B, 2, 4	0	16 + 1[d]
			Class 2	C-F-1	826	147	70	16		0	11 + 4[b] + 1[d]

Table 5-1

STRUCTURAL ELEMENT SELECTION (SES)
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS

System	High Safety Significant Segments (No. of HSS in Augmented Program / Total No. of Segments in Aug. Program)	Degradation Mechanism(s)	Safety Class	ASME Code Exam Category	Total Weld Count (Welds requiring Volumetric (Vol) and Surface (Sur))		ASME XI Program Examinations		RI-ISI[a]		
					Vol & Sur	Sur only	Vol & Sur	Sur only	SES Matrix Region	No. of Aug. Program Segments	Number of Exam Locations
SS	0 (0/0)	TF	Class 1	N/A	0	0	0	0	4	0	0
			Class 2	N/A	0	0	0	0			
TOTAL	118 (8 / 88)	FAC/TF, TF, SCC/TF, SCC/TF/VF/SS TF/VF, WH, VF	Class 1		469	682	129	175		0	38 NDE + 3 VIS
			Class 2		1729	514	157	40		88	55 NDE + 28 VIS
			Total		2198	1196	286	215		88	93 NDE + 31 VIS

Table 5-1

STRUCTURAL ELEMENT SELECTION (SES)
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS

System	High Safety Significant Segments (No. of HSS in Augmented Program / Total No. of Segments in Aug. Program)	Degradation Mechanism(s)	Safety Class	ASME Code Exam Category	Total Weld Count (Welds requiring Volumetric (Vol) and Surface (Sur))		ASME XI Program Examinations		RI-ISI[a]		
					Vol & Sur	Sur only	Vol & Sur	Sur only	SES Matrix Region	No. of Aug. Program Segments	Number of Exam Locations

Summary: Current ASME Section XI selects a total of 501 welds while the proposed RI-ISI program selects a total of 93 welds (124 - 31 visual exams), which results in a 81% reduction.

Degradation Mechanisms: VF – Vibratory Fatigue; TF – Thermal Fatigue; FAC – Flow-Assisted Corrosion, SCC – Stress Corrosion Cracking; SS – Striping/Stratification. “X/X” indicates combination of mechanisms

Notes for Table 5-1
a. System pressure test requirements and VT-2 visual examinations shall continue in all ASME Code Class systems.
b. VT-2 examination at one location within segment.
c. Augmented programs for erosion-corrosion and/or high energy line break continue.
d. Examinations added for change in risk considerations (Total of four segments- two RC and two SI).
e. VT-2 for entire segment.
f. Included also in augmented program for erosion-corrosion and/or high energy line break. Augmented program continues.

6. SUMMARY OF RESULTS AND CONCLUSIONS

A partial scope (Class1 and Class 2) risk-informed ISI application has been completed for BV1. Upon review of the proposed risk-informed ISI examination program given in Table 5-1, an appropriate number of examinations are proposed for the high safety significant segments across the Class 1 and Class 2 portions of the plant piping systems. Resources to perform examinations currently required by ASME Section XI in the Class 1 and Class 2 portions of the plant piping systems, though reduced, are distributed to address the greatest amount of risk within the scope. Thus, the change in risk principle of Regulatory Guide 1.174 is maintained. The examinations performed will address specific damage mechanisms postulated for the selected locations through appropriate examination selection. Additional examinations will be performed when evidence of degradation is discovered.

From a risk perspective, the PRA dominant accident sequences include station blackout, small LOCAs and steam generator tube rupture events with loss of core cooling from the secondary side.

For the RI-ISI program, appropriate sensitivity and uncertainty evaluations have been performed to address variations in piping failure probabilities and PRA consequence values along with consideration of deterministic insights to assure that all high safety significant piping segments have been identified.

As a risk-informed application, this submittal meets the intent and principles of Regulatory Guide 1.174.

7. REFERENCES/DOCUMENTATION

WCAP-14572, Revision 1-NP-A, “Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report,” February 1999

WCAP-14572, Revision 1-NP-A, Supplement 1, “Westinghouse Structural Reliability and Risk Assessment (SRRA) Model for Piping Risk-Informed Inservice inspection,” February 1999

U.S. Nuclear Regulatory Commission, “An Approach Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” Regulatory Guide 1.174, July 1998.

U.S. Nuclear Regulatory Commission, “Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants”, Regulatory Guide 1.26, Rev. 2, February 1976.

<u>Supporting Onsite Documentation</u>

1. Segment Definition Calculations:
   - 1.1 8700-DMC-1305, Revision 0, 4/16/02, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Quench Spray System”.
   - 1.2 8700-DMC-1306, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Recirculation Spray System, Revision 0, 4/16/02”.
   - 1.3 8700-DMC-1307, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Reactor Plant Vents and Drains System, Revision 0, 4/16/02”.

1.4 8700-DMC-1308, Revision 1, 1/7/02, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Chemical and Volume Control System”.
1.5 8700-DMC-1309, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Steam Generator Blowdown System, Revision 1, 1/2/02”.
1.6 8700-DMC-1310, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Steam Generator Feedwater System, Revision 0, 4/16/02”.
1.7 8700-DMC-1311, Revision 1, 1/3/02, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Main Steam System”.
1.8 8700-DMC-1312, Revision 1, 1/3/02, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Reactor Plant Sampling System”.
1.9 8700-DMC-1313, Revision 0, 8/14/01, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Post DBA Hydrogen Control System”
1.10 8700-DMC-1314, Revision 1, 1/3/02, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Containment Isolation System”.
1.11 8700-DMC-1315, Revision 0, 9/6/01, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Reactor Coolant System”
1.12 8700-DMC-1316, Revision 0, 9/6/01, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Residual Heat Removal System”
1.13 8700-DMC-1317, Revision 0, 1/15/02, “Beaver Valley Unit 1 RI-ISI Segment Definition for the Safety Injection System”.

2. 8700-DMC-1333, Revision 0, 10/15/01, “Beaver Valley Unit 1 Risk-Informed ISI Indirect (Spatial) Consequence Evaluation”.
3. 8700-DMC-1386, Revision 1, 1/17/02, “Risk-Informed In-Service Inspection (RI-ISI) PRA Calculation for Unit 1 RI-ISI Systems”.
4. SRRA Documentation**:**
   1. 8700-DMC-1318, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Reactor Plant Vents and Drains System.
   2. 8700-DMC-1319, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Containment Depressurization System (QS).
   3. 8700-DMC-1320, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Containment Depressurization System (RS).
   4. 8700-DMC-1321, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Residual Heat Removal (RH) System.
   5. 8700-DMC-1322, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Steam Generator Blowdown (BD) System.
   6. 8700-DMC-1323, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for Reactor Coolant (RC) System.
   7. 8700-DMC-1324, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Steam Generator Feedwater (FW) System.
   8. 8700-DMC-1325, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Chemical and Volume Control (CH) System.
   9. 8700-DMC-1326, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Main Steam (MS) System.

10. 8700-DMC-1327, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Post-DBA Hydrogen Control (HY) System.
11. 8700-DMC-1328, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Safety Injection (SI) System.
12. 8700-DMC-1329, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Containment Isolation (CI) System.
13. 8700-DMC-1331, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Reactor Plant Sampling System (SS).

5. CN-RRA-01-31, Revision 0 “Beaver Valley Power Stations 1 & 2 Risk Evaluation for RI-ISI”, 2/20/02
6. CN-RRA-02-17, Revision 0, “Beaver Valley Power Station 1 Perdue Evaluation”, 4/8/02
7. CN-RRA-02-29, Revision 0, “Beaver Valley Power Station 1 Change In Risk Evaluation”, 4/5/02
8. Expert Panel Data:
   8.1 FENOC-01-356, “Expert Panel Review Materials”, 12/17/01
   8.2 ND1MLM:0184, “Risk Informed ISI Expert Panel”, 1/2/02
   8.3 FENOC-02-45, “RI-ISI Expert Panel Action Item Resolutions”, 1/28/02
   8.4 ND1MLM:0214, “Results of the Expert Panel Review of Comment Resolution”, 3/11/02
   8.5 CN-RRA-01-69, Revision 0, “Beaver Valley Power Station 1 Expert Panel Database”, 5/16/02

ATTACHMENT 2

FirstEnergy Nuclear Operating Company

Beaver Valley Power Station Unit No. 2

Risk-Informed Inservice Inspection Piping Program

Using the Westinghouse Owners Group (WOG) Methodology

Revision 0

June 2002

RISK-INFORMED INSERVICE INSPECTION PROGRAM PLAN

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1. INTRODUCTION/RELATION TO NRC REGULATORY GUIDE RG-1.174

1.1 Introduction

Inservice inspections (ISI) are currently performed on piping to the requirements of the ASME Boiler and Pressure Vessel Code Section XI, 1989 Edition as required by 10CFR50.55a. The unit is currently in the second inspection period of the second inspection interval as defined by the Code for Program B.

The objective of this submittal is to request a change to the ISI program plan for piping through the use of a risk-informed ISI program. The risk-informed process used in this submittal is described in Westinghouse Owners Group WCAP-14572, Revision 1-NP-A, "Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report," and WCAP-14572, Revision 1-NP-A, Supplement 1, "Westinghouse Structural Reliability and Risk Assessment (SRRA) Model for Piping Risk-Informed Inservice Inspection," (referred to as "the WCAP" for the remainder of this document)."

As a risk-informed application, this submittal meets the intent and principles of Nuclear Regulatory Commission (NRC) Regulatory Guide 1.174. Further information is provided in Section 3.10 relative to defense-in-depth.

1.2 PRA Quality

The Beaver Valley Power Station Unit 2 Level 1 and Level 2 probabilistic risk assessment (PRA) model, Version BV2REV2 dated October 31, 1997 was used to evaluate the consequences of pipe ruptures during operation of BVPS Unit 2 in Modes 1 and 2. The base core damage frequency (CDF) and base large, early release frequency (LERF) from this version of the PRA model are 7.14E-05/yr and 1.22E-06/yr, respectively.

The suggested schedule for PRA model updates are 3-year intervals. Each unit's PRA model update is also recommended to be staggered 18 months apart from the other unit, to avoid overlap in the update process between PRA models and impacted programs. The administrative guidance for this activity is contained in administrative procedures.

Based on past PRA model updates performed for the Beaver Valley Units (two on Unit 2), it was observed that most PRA model updates do not change significantly due to plant modifications and new failure data. To ensure that this remains valid, administrative procedures require that a PRA model be revised any time a plant modification increases the CDF by more than 20% above the baseline CDF value. The impacts of these plant modifications are documented and analyzed for any increases in the baseline CDF and LERF. To date no single modification has increased CDF by more than 3% and the accumulated change in CDF due to plant modifications since the last PRA model update at Unit 2 are about a .2% increase. Additionally, keeping within the established Maintenance Rule performance criteria for risk significant Systems, Structures, and Components (SSCs), helps to ensure that the impact on CDF due to equipment unavailability and failures remains minimal. Therefore, the current Beaver Valley PRA models are meeting the intent of Regulatory Guide 1.174 in that they reflect the actual design, construction, operational practices and experiences as they relate to risk significant systems. In the past, the significant changes to the PRA models were typically due to removing conservatism of previous models (e.g., using best estimate analyses in place of design bases analyses) or by taking additional credit for backup components (e.g., using LHSI

pumps in-place of HHSI pumps during small break LOCAs). Other significant changes involve improved state-of-the-art knowledge on PRA issues. Furthermore, an evaluation based on the Appendix B of the EPRI PSA Applications Guide, was performed to confirm that the PRA conforms to the industry state-of-the-art with respect to completeness of coverage of potential scenarios.

The PRA model has been extensively reviewed including internal multi-disciplined reviews during the IPE process, and internal and external PRA consultant reviews during the PRA model updates.

During the NRC's review of the Individual Plant Evaluation (IPE), concerns were identified regarding the limited consideration of pre-initiator human actions. The NRC noted that the Human Reliability Analysis could have been strengthened by the use of a reasonably rigorous process to identify potential pre-initiator human error contributions to system unavailability. System unavailability has been monitored as part of implementation of the Maintenance Rule, including any system unavailability due to human errors. The plant specific data collected for system unavailability was then used in the PRA model updates performed since the initial IPE submittal. To identify pre-initiator human error contributions to system unavailability, possible misalignments that could reasonably occur on standby systems were postulated and the impact on top event logic models and minimal cutsets was determined. The probability that the system/train is unavailable due to a misalignment event was calculated based on generic failure rates for errors of omission, the frequency of tests and maintenance on standby systems, and the duration of the misalignment. System unavailability resulting from human errors is therefore accounted for in the current models.

Several PRA model changes for the upcoming Unit 2 PRA model update were not incorporated into the PRA in time to support this submittal (i.e., RCP seal LOCA model updates). Preliminary results show that the majority of core damage frequency reduction will come from this refined modeling and applying state-of-the-art knowledge type activities. The RI-ISI Expert Panel was advised of these modifications and their impact on the piping systems. Therefore, these concerns were considered as part of the expert panel deliberations.

2. PROPOSED ALTERNATIVE TO ISI PROGRAM

2.1 ASME Section XI

ASME Section XI Categories B-F, B-J, C-F-1 and C-F-2 currently contain the requirements for examining via non-destructive examination (NDE) for Class 1 and 2 piping components. The proposed program is limited to ASME Class 1 and Class 2 piping, including piping currently exempt from NDE requirements. The alternative risk-informed inservice inspection (RI-ISI) program for piping is described in the WCAP. The RI-ISI program will be substituted for the current examination program on piping in accordance with 10 CFR 50.55(a)(3)(i) by implementing an alternate methodology that provides an acceptable level of quality and safety. Other examination categories will be unaffected. The WCAP provides the requirements defining the relationship between the risk-informed examination program and the remaining unaffected portions of ASME Section XI.

2.2 Augmented Programs

The augmented inspection programs remain unchanged as a result of the RI-ISI program.

3. RISK-INFORMED ISI PROCESSES

The processes used to develop the RI-ISI program are consistent with the methodology described in the WCAP.

The process that is being applied, involves the following steps:

- Scope Definition
- Segment Definition
- Consequence Evaluation
- Failure Assessment
- Risk Evaluation
- Expert Panel Categorization
- Structural Element/NDE Selection
- Implement Program
- Feedback Loop

Deviations

As part of the risk evaluation described in Section 3.5, the uncertainty analysis as described on page 125 of the WCAP was performed and is now included as part of the base process.

Structural Element/NDE Selection; Change In Risk

The change in risk methodology described in Section 3.10 deviated from the methodology for segments located inside containment and segments that interface with the Reactor Coolant System (RCS) such that radiation monitors and sump level will detect a leak. The RCS was defined to be the Class 1 primary loop pressure boundary piping. Beaver Valley Power Station Unit 2 capability to detect a leak within the RCS is defined to be 1 gpm per Tech Spec documentation. 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.

3.1 Scope of Program

The scope of this program is ASME Class 1 and 2 piping, including piping exempt from current requirements. The piping systems included in the risk-informed ISI program are provided in Table 3.1-1.

Table 3.1-1: System Selection and Segment Definition for Beaver Valley Power Station 2 Class 1 and 2 Piping

System Description	PRA	Section XI	Number of Segments
Steam Generator Blowdown System (BDG)	Yes	No	24
Chemical and Volume Control System (CHS)	Yes	Yes	160
Containment Isolation System (CI)	Yes	No	84
Reactor Plant Drains and Vents Systems (DAS)	Yes	Yes	7
Steam Generator Feedwater System (FWA)	Yes	Yes	57
Gaseous Nitrogen System (GNS)	Yes	No	6
Hydrogen Control System (HCS)	Yes	No	40
Main Steam System (MSS)	Yes	Yes	53
Quench Spray System (QSS)	Yes	Yes	38
Reactor Coolant System (RCS)	Yes	Yes	91
Residual Heat Removal System (RHS)	Yes	Yes	58
Recirculation Spray System (RSS)	Yes	Yes	68
Safety Injection System (SIS)	Yes	Yes	172[1]
Sampling System (SSR)	Yes	No	59
Total			917

Note: 1. Three “Not Used” segments under the SIS identifier are included in the segment count.

3.2 Segment Definitions

Once the systems to be included in the program are determined, the piping for these systems is divided into segments.

The number of pipe segments defined for the Class 1 and 2 piping (14 systems) is summarized in Table 3.1-1. The Valve Operating Number Diagrams and Piping Flow Diagrams were used to define the segments.

3.3 Consequence Evaluation

The consequences of pressure boundary failures are measured in terms of core damage and large early release. The impact on these measures due to both direct and indirect effects was considered. Table 3.3-1 summarizes the postulated consequences for each system.

Table 3.3-1
Summary of Postulated Consequences by System

System	Summary of Consequences
Steam Generator Blowdown System (BDG)	Direct effects: Reactor Trip (RT), Partial Loss of Main Feedwater (PLMFW), Steam Line Break Upstream of MSIV Initiating Events. Loss of Auxiliary Feedwater and Main Feedwater to Steam Generators. Loss of the containment pressure boundary. Indirect effects: None
Chemical and Volume Control System (CHS)	Direct effects: Reactor Trip (RT), Small or Medium LOCA Initiating Events. The following consequences would occur due to pipe failures in various locations within the CHS. • Loss of High Head and Low Head Safety Injection • Loss of recirculation • Loss of seal injection to one or more RCP seals • Loss of one or both charging trains • Loss of Letdown • Loss of normal and emergency boration • Loss of Refueling Water Storage Tank inventory outside of containment • Loss of Containment Sump Inventory outside of containment • Loss of the containment pressure boundary. Indirect effects: Indirect effects for spray were identified that disabled the system function of alternate trains of CHS and an SIS train.

Table 3.3-1 Summary of Postulated Consequences by System	
System	Summary of Consequences
Containment Isolation System (CI)	Direct effects: Loss of Primary Component Cooling Initiating Event. Loss of RCP thermal barrier and motor cooling. Loss of cooling to the RHR heat exchangers. Loss of the containment pressure boundary. Indirect effects: None
Reactor Plant Drains and Vents Systems (DAS)	Direct effects: Loss of the containment pressure boundary. Indirect effects: None
Steam Generator Feedwater System (FWA)	Direct effects: Reactor Trip (RT), Partial Loss of Main Feedwater (PLMFW), Main Feedwater Line Break (MFWLB), and Total Loss of Main Feedwater (TLMFW) Initiating Events. Loss of main or auxiliary feedwater to one or more steam generators. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.
Gaseous Nitrogen System (GNS)	Direct effects: Loss of accumulator injection. Loss of the containment pressure boundary. Indirect effects: None
Hydrogen Control System (HCS)	Direct effects: Loss of the containment pressure boundary. Indirect effects: None
Main Steam System (MSS)	Direct effects: Steam Line Break Upstream of MSIV (SLBI), Steam Line Break Downstream of MSIV (SLBD), and Steam Line Break in Common RHR Valve Line (SLBC) Initiating Events. Loss of Main Feedwater to all steam generators due to MFW pump trip on SI signal. Failure of one or more of the steam supply paths to the Turbine Driven Auxiliary Feedwater Pump. Disable the atmospheric steam dump valves on the faulted steam generator. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.

Table 3.3-1 Summary of Postulated Consequences by System	
System	Summary of Consequences
Quench Spray System (QSS)	Direct effects: Loss of RWST inventory outside containment. Loss of one or both trains of QSS, LHSI / HHSI injection and Recirculation. Loss of the containment pressure boundary. Indirect effects: Jet Impingement/Spray and Flooding fails Auxiliary Feedwater pumps, Low Head SI pump, Recirculation Spray pump or Quench Spray pump.
Reactor Coolant System (RCS)	Direct effects: Depending upon location and size, segment failure will result in either a small, medium, or large break LOCA. In addition, failures of other functions such as hot or cold leg injection or recirculation, loss of RHR, loss of pressurizer spray, and loss of letdown or charging could occur. Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RCS piping failures were evaluated and mitigated as part of design basis activities.
Residual Heat Removal System (RHS)	Direct effects: Small, medium, or large LOCA Initiating Events. Loss of the containment pressure boundary. Depending upon location, segment failure (without operator action) results in a loss of one or more of the following functions: • Loss of RHR • Loss of HHSI and LHSI hot leg recirculation • Loss of accumulator injection Operator action, in most cases, would isolate the faulted RHS train. Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RHS piping failures were evaluated and mitigated as part of design basis activities.

Table 3.3-1 Summary of Postulated Consequences by System	
System	Summary of Consequences
Recirculation Spray System (RSS)	Direct effects: Loss of containment sump inventory due to the failure outside containment. Failure will eventually lead to failure of all RSS and all HHSI/LHSI recirculation. Loss of containment and decay heat removal. Loss of the containment pressure boundary. Indirect effects: None
Safety Injection System (SIS)	Direct effects: Reactor Trip (RT); Small, Medium or Large LOCA Initiating Events. Depending upon location, segment failure can result in a loss of one or more of the following functions: • Loss of accumulator injection • High Pressure Injection • High Pressure Recirculation • Low Pressure Injection • Low Pressure Recirculation • Loss of RWST inventory outside containment, HHSI, LHSI, QSS, and RSS Pumps for Injection and Recirculation Loss of the containment pressure boundary. Indirect effects: None
Sampling System (SSR)	Direct effects: Reactor Trip (RT) and Partial Loss of Main Feedwater (PLMFW) Initiating Events. Depending upon location segment failure can result in a loss of one of the following: • Loss of auxiliary feedwater to one steam generator • Loss of affected accumulator • Loss of one charging pump and boration flow to other operable pumps. Loss of the containment pressure boundary. Indirect effects: None

3.4 Failure Assessment

Failure estimates were generated utilizing industry failure history, plant specific failure history and other relevant information. An engineering team was established that has access to expertise from ISI, NDE, materials, stress analysis and system engineering. 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, A-Version, Supplement 1. The WinSRRA code was 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-14572, A-Version Supplement 1. All the piping configurations included in the RI-ISI program except for segments SSR-057, SSR-058, and SSR-059 could be adequately modeled using the code. WinSRRA was used to determine failure probabilities where appropriate in these segments but the segments contain pressure fit components. The industry history for failure of these fittings was determined to be controlling when compared to the values determined from WinSRRA. The controlling values were used in the risk assessments for these segments.

The engineering team assessed industry and plant experience, plant layout, materials, and operating conditions to identify the potential failure mechanisms and causes. Information was gathered from various sources by the engineering team to provide input for the SRRA model. BV2 snubber failure history was reviewed to identify any potential effects that could increase piping failure probability.

Consideration was also given to whether a segment is addressed by either a plant stress corrosion cracking or erosion corrosion augmented program. This information is used to determine which failure probability is used in the risk-informed ISI process. The effects of ISI on existing augmented programs are included in the risk evaluation used to assist in categorizing the segments as described on page 105 of the WCAP. The failure probabilities used in the risk-informed process are documented and maintained in the plant records.

Table 3.4-1 summarizes the failure probability estimates for the dominant potential failure mechanisms by system. Table 3.4-1 also describes why the degradation mechanisms could occur at various locations within the system. Full break cases may be included but only when pipe whip is of concern. All instances where pipe whip would be a concern were addressed as part of the original plant design for BV2.

Table 3.4-1 Failure Probability Estimates (without ISI)				
System	Dominant Potential Degradation Mechanism(s)/Combinations(s)	Failure Probability Range at 40 Years with No ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
BDG	Erosion/Corrosion, Thermal Fatigue	6.91E-08 – 4.91E-05	SYS 2.29E-10 - 1.67E-04	System is included in the current Flow Accelerated Corrosion Augmented Inspection program.
CHS	Thermal Fatigue	2.00E-07 – 6.93E-05	MLOCA 2.04E-10 - 1.73E-06 SLOCA 1.88E-10 - 2.07E-05 SYS 1.67E-10 - 1.89E-05	
	Thermal & Vibratory Fatigue	3.48E-05 – 7.21E-03	SLOCA 3.65E-09 - 5.22E-03 SYS 1.38E-09 - 5.22E-03	Vibration occurs near the orifices in various locations throughout the system. Downstream of the charging pumps and letdown heat exchanger are the critical orifice locations. Vibration occurs on small branch connections near pumps.
CI	Erosion/Corrosion, Thermal Fatigue	2.44E-05 – 2.44E-05	SYS 1.85E-10 - 1.06E-07	Microbiological mechanisms were identified in the river water portions of the piping lines.
	Thermal Fatigue	8.59E-08 – 3.16E-05	SYS 9.86E-11 - 3.37E-06	
DAS	Thermal Fatigue	6.46E-07 - 3.32E-05	SYS 1.33E-09 - 1.01E-07	
FWA	Erosion/Corrosion, Thermal Fatigue	1.51E-08 – 5.21E-06	SYS 1.50E-12 - 1.20E-06	System is included in the current Flow Accelerated Corrosion Augmented Inspection program.
GNS	Thermal Fatigue	1.08E-05 – 6.04E-05	SYS 1.08E-05 – 6.04E-05	Gas segments where in all cases a small leak would disable the system function.
HCS	Thermal Fatigue	2.58E-06 – 1.05E-05	SYS 2.58E-06 – 1.05E-05	Gas segments where in all cases a small leak would disable the system function.

Table 3.4-1 Failure Probability Estimates (without ISI)				
System	Dominant Potential Degradation Mechanism(s)/Combinations(s)	Failure Probability Range at 40 Years with No ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
MSS	Erosion/Corrosion, Thermal Fatigue	2.49E-07 – 8.71E-04	SYS 2.50E-10 - 6.58E-05	System is included in the current Flow Accelerated Corrosion Augmented Inspection program.
QSS	Thermal Fatigue	4.70E-07 - 3.84E-05	SYS 6.71E-14 - 8.79E-08	
	Vibrational Fatigue	2.45E-07 - 1.44E-05	SYS 4.75E-10 - 5.01E-06	Vibration occurs on small branch connections near pumps.
RCS	Stress Corrosion/Cracking, Thermal Fatigue	5.59E-10 – 2.07E-05	LLOCA 5.78E-11 - 1.50E-05 MLOCA 3.49E-12 - 1.50E-05 SLOCA 3.10E-12 - 1.50E-05 SYS 3.46E-12 - 1.51E-05	
	Stress Corrosion /Cracking, Thermal Fatigue, Vibrational Fatigue, Striping/Stratification	1.12E-05 – 3.03E-04	LLOCA 6.34E-10 - 7.01E-05 MLOCA 6.74E-10 - 7.12E-05 SLOCA 7.93E-10 - 7.20E-05 SYS 2.84E-09 - 1.89E-04	Industry history identifies thermal striping or stratification occurs in the pressurizer surge line. Temperature monitoring is on going but no evidence of fatigue or structural concerns have been noted.
	Thermal Fatigue	2.15E-08 – 1.84E-06	SLOCA 4.22E-11 - 1.41E-06 SYS 4.70E-11 - 1.98E-06	
RHS	Stress Corrosion /Cracking, Thermal Fatigue	9.11E-08 – 7.85E-07	LLOCA 3.46E-10 - 3.24E-07 MLOCA 4.45E-10 - 3.31E-07 SLOCA 5.20E-10 - 3.36E-07 SYS 3.96E-10 - 3.48E-07	
	Thermal Fatigue	9.11E-08 – 9.32E-05	SLOCA 6.02E-09 - 5.90E-08 SYS 1.50E-11 - 1.52E-05	
RSS	Thermal Fatigue	4.18E-07 - 4.71E-05	SYS 4.56E-14 - 1.07E-05	
SIS	Thermal Fatigue	1.58E-07 – 4.12E-04	LLOCA 3.31E-09 - 1.27E-04 MLOCA 3.12E-10 - 1.35E-04 SLOCA 2.50E-10 - 1.39E-04 SYS 1.03E-10 - 1.98E-04	

Table 3.4-1 Failure Probability Estimates (without ISI)				
System	Dominant Potential Degradation Mechanism(s)/Combinations(s)	Failure Probability Range at 40 Years with No ISI		Comments
		Small leak	Disabling leak (by disabling leak rate)*	
SSR	Thermal Fatigue	9.11E-08 – 4.91E-05	SLOCA 3.52E-10 - 2.58E-07 SYS 8.76E-10 - 1.26E-05	

Notes:
** - Disabling leak rate – LLOCA, MLOCA, SLOCA, and SYS (system disabling leak).*

3.5 Risk Evaluation

Each piping segment within the scope of the program was evaluated to determine its core damage frequency (CDF) and large, early release frequency (LERF) due to the postulated piping failure. Calculations were also performed with and without operator action.

Once this evaluation is completed, the total pressure boundary core damage frequency and large early release frequency are calculated by summing across the segments for each system.

The uncertainty analysis as described on page 125 of the WCAP was performed and is now included as part of the base process. The results of these calculations are presented in Table 3.5-1. The core damage frequency due to piping failure without operator action is 1.90E-06/year, and with operator action is 1.36E-06/year. The large early release frequency due to piping failure without operator action is 2.33E-08/year, and with operator action is 2.15E-08/year.

To assess safety significance, the risk reduction worth (RRW) and risk achievement worth (RAW) were calculated for each piping segment.

Table 3.5-1
Number of Segments and Piping Risk Contribution by System (without ISI)

System	# of Segments	CDF without Operator Action (/yr)	CDF with Operator Action (/yr)	LERF without Operator Action (/yr)	LERF with Operator Action (/yr)
BDG	24	1.16E-08	1.16E-08	1.30E-10	1.24E-10
CHS	160	2.34E-07	1.32E-08	1.25E-09	1.41E-10
CI-	84	1.65E-09	1.65E-09	7.30E-12	7.30E-12
DAS	7	0.00E+00	0.00E+00	0.00E+00	0.00E+00
FWA	57	3.36E-12	1.14E-12	3.22E-13	6.05E-14
GNS	6	3.47E-14	3.47E-14	0.00E+00	0.00E+00
HCS	40	0.00E+00	0.00E+00	0.00E+00	0.00E+00
MSS	53	8.79E-11	9.60E-11	1.32E-12	2.45E-12
QSS	38	1.54E-09	9.88E-10	2.29E-11	1.96E-11
RCS	91	5.32E-07	5.32E-07	8.24E-09	8.23E-09
RHS	58	7.46E-10	7.46E-10	1.16E-11	1.16E-11
RSS	68	6.46E-11	4.16E-11	1.63E-12	1.45E-12
SIS	172	1.11E-06	8.04E-07	1.36E-08	1.29E-08
SSR	59	9.44E-10	4.28E-11	8.39E-12	1.45E-12
Total	917	1.90E-06	1.36E-06	2.33E-08	2.15E-08

3.6 Expert Panel Categorization

The final safety determination, (i.e., high and low safety significance), of each piping segment was made by the expert panel using both probabilistic and deterministic insights. The expert panel was comprised of personnel who have expertise in the following fields: probabilistic safety assessment, inservice examination, nondestructive examination, stress and material considerations, plant operations, plant and industry maintenance, repair and failure history, system design and operation, and SRRA methods including uncertainty. Members associated with the Maintenance Rule were used to ensure consistency with the other PRA applications.

The expert panel had the following positions represented by the permanent member at all times during the expert panel meeting.

- Probabilistic Risk Assessment (PRA Supervisor)
- Operations (Nuclear Operations (ANSS))
- Inservice Inspection and Nondestructive Examination (NDE Inspection)
- Plant & Industry Maintenance (Maintenance Engineering/Maintenance Rule)
- Repair, and Failure History (System Engineer)
- System Design and Operation (System Engineer)
- Licensing and Safety Analysis (Licensing/Safety Engineer)
- Materials (Materials Engineering)
- Stress (Structural Engineering)

A minimum of 4 members or alternates filling the above positions constituted a quorum. This core team of panel members was supplemented by other experts, including an ISI Engineer and PRA Engineer, as required for the piping system under evaluation.

FirstEnergy Nuclear Operating Company appointed the expert panel chairperson. The chairperson conducted and ruled on the proceedings of the meetings.

Members and alternates received training and indoctrination in the risk-informed inservice inspection selection process. They were indoctrinated in the application of risk analysis techniques for ISI. These techniques included risk importance measures, threshold values, failure probability models, failure mode assessments, PRA modeling limitations and the use of expert judgment. Training documentation is maintained with the expert panel's records.

Worksheets were provided to the panel on each system for each piping segment, containing information pertinent to the panel's selection process. This information, in conjunction with each panel member's own expertise and other documents as appropriate, were used to determine the safety significance of each piping segment.

A consensus process was used by the expert panel. Consensus was defined as unanimous for this initial application of the RI-ISI methodology. The chairperson permitted active discussion during the proceedings and appropriate time for deliberation.

Minutes of each meeting were generated. The minutes included the names of members and alternates in attendance and whether a quorum was present. The minutes contained relevant discussion summaries and the results of membership voting. These minutes are available as program records.

3.7 Identification of High Safety Significant Segments

The number of high safety significant segments for each system, as determined by the expert panel, is shown in Table 3.7-1 along with a summary of the risk evaluation identification of high safety significant segments (HSS).

Table 3.7-1
Summary of Risk Evaluation and Expert Panel Categorization Results

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)
BDG	1	5	18	0	18	24 (0)
CHS	2	21	137	14	18	33 (33)
CI-	0	2	82	0	0	0 (0)
DAS	0	0	7	0	0	0 (0)
FWA	0	0	57	0	57	57 (0)
GNS	0	0	6	0	0	0 (0)
HCS	0	0	40	0	0	0 (0)
MSS	0	0	53	0	53	53 (8)
QSS	0	2	36	2	13	15 (15)
RCS	24	2	65	0	2	26 (26)
RHS	0	1	57	1	0	1 (1)
RSS	0	0	68	0	0	0 (0)
SIS	31	27	114	1	6	24 (24)
SSR	0	0	59	0	0	0 (0)
TOTAL	58	60	799	18	167	233 (107)

3.8 Structural Element and NDE Selection

The structural elements in the high safety significant piping segments were selected for inspection and appropriate non-destructive examination (NDE) methods were defined.

The initial program being submitted addresses the HSS piping components placed in regions 1 and 2 of Figure 3.7-1 in the WCAP. Segments considered as “high failure importance” (Region 1) were identified as all segments being affected by an active failure mechanism or analyzed to

be highly susceptible to a failure mechanism (probability of large leak at 40 years generally exceeds 1E-04). Region 3 piping components, which are low safety significant, are to be considered in an Owner Defined Program and are not considered part of the program requiring approval. Region 1, 2, 3 and 4 piping components will continue to receive Code required pressure testing, as part of the current ASME Section XI program. For the 917 piping segments that were evaluated in the RI-ISI program, Region 1 contains 10 segments, Region 2 contains 97 segments, Region 3 contains 129 segments, and Region 4 contains 678 segments. Three segment identifiers in the CHS system sequence were not used to identify a piping segment but included in the segment counts. These segments were not included in the region counts.

The number of locations to be inspected in a HSS segment was determined using a Westinghouse statistical (Perdue) model as described in section 3.7 of the WCAP. All of the HSS piping segments in Region 1 and Region 2 were evaluated using the Perdue model.

Table 4.1-1 in the WCAP was used as guidance in determining the examination requirements for the HSS piping segments. VT-2 visual examinations are scheduled in accordance with the station's pressure test program that remains unaffected by the risk-informed inspection program.

Additional Examinations

Since the risk-informed inspection program will require examinations on a large number of elements constructed to lesser pre-service inspection requirements, the program in all cases will determine through an engineering evaluation the root cause of any unacceptable flaw or relevant condition found during examination. The evaluation will include the applicable service conditions and degradation mechanisms to establish that the element(s) will still perform their intended safety function during subsequent operation. Elements not meeting this requirement will be repaired or replaced.

The evaluation will include whether other elements on the segment or segments are subject to the same root cause and degradation mechanism. Additional examinations will be performed on these elements up to a number equivalent to the number of elements initially required to be examined on the segment or segments. If unacceptable flaws or relevant conditions are again found similar to the initial problem, the remaining elements identified as susceptible will be examined. No additional examinations will be performed if there are no additional elements identified as being susceptible to the same service related root cause conditions or degradation mechanism.

3.9 Program Relief Requests

An attempt has been made to provide a minimum of >90% coverage (per Code Case N-460) when performing the risk-informed examinations. However, not all limitations will be known until the examination is performed, since some locations will be examined for the first time by the specified techniques.

When the examination does not meet >90% coverage, the process outlined in Section 4.0 of the WCAP will be followed.

3.10 Change in Risk

The risk-informed ISI program has been done in accordance with Regulatory Guide 1.174, and the risk from implementation of this program is expected to slightly decrease when compared to that estimated from current requirements.

The change in risk calculations were performed according to all the guidelines provided on page 213 of the WCAP. A comparison between the proposed RI-ISI program and the current ASME Section XI ISI program was made to evaluate the change in risk. The approach evaluated the change in risk with the inclusion of the probability of detection as determined by the SRRA model. All four criteria for accepting the results discussed on page 214 and 215 in the WCAP were met (or adjustments were made to add segments until the criteria were met). This evaluation resulted in the identification of 2 RCS piping segments for which examinations are now required.

The change in risk methodology deviated from the methodology for segments located inside containment and that interface with the RCS such that radiation monitors and sump level will detect a leak. The Reactor Coolant System was defined to be the Class 1 primary loop pressure boundary piping. Beaver Valley Power Station Unit 2 capability to detect a leak within the RCS is defined to be 1 gpm per Tech Spec documentation. For these segments, the failure probability “with ISI” for those being examined by NDE and “without ISI” for those not being examined is used along with credit for leak detection.

The results from the risk comparison are shown in Table 3.10-1. As seen from the table, the RI-ISI program reduces the risk associated with piping CDF/LERF slightly more than the current Section XI program while reducing the number of examinations. Table 3.10-1 also includes the systems that are the main contributors to the risk reduction in moving from the current program to the RI-ISI program. The primary basis for this risk reduction is that examinations are now being placed on piping segments that are high safety significant and which are not examined by NDE in the current ASME Section XI ISI program.

<u>Defense-In-Depth</u>

The reactor coolant piping will continue to receive a system pressure test and visual VT-2 examination as currently required by the ASME XI Code. Larger reactor coolant loop piping segments were retained in the program for “defense-in-depth” considerations. All reactor vessel dissimilar metal welds were selected for examination.

Table 3.10-1 COMPARISON OF CDF/LERF FOR CURRENT SECTION XI AND RISK-INFORMED ISI PROGRAMS AND THE SYSTEMS WHICH CONTRIBUTED SIGNIFICANTLY TO THE CHANGE		
Case (Systems Contributing to Change)	Current Section XI	Risk-Informed
CDF No Operator Action	8.24E-07	8.02E-07
• BDG	1.16E-08	1.16E-08
• CHS	2.45E-07	2.31E-07
• CI	1.65E-09	1.65E-09
• MSS	8.79E-11	8.79E-11
• QSS	1.50E-09	2.68E-10
• RCS	1.69E-07	1.69E-07
• RSS	6.43E-11	6.46E-11
• SIS	3.94E-07	3.88E-07
• SSR	9.44E-10	9.44E-10
CDF with Operator Action	2.81E-07	2.73E-07
• BDG	1.16E-08	1.16E-08
• CHS	2.33E-09	1.11E-09
• CI	1.65E-09	1.65E-09
• MSS	9.60E-11	9.60E-11
• QSS	9.79E-10	1.71E-11
• RCS	1.69E-07	1.69E-07
• RSS	4.16E-11	4.16E-11
• SIS	9.54E-08	8.92E-08
• SSR	4.28E-11	4.28E-11

Table 3.10-1 (continued) COMPARISON OF CDF/LERF FOR CURRENT SECTION XI AND RISK-INFORMED ISI PROGRAMS AND THE SYSTEMS WHICH CONTRIBUTED SIGNIFICANTLY TO THE CHANGE		
Case (Systems Contributing to Change)	Current Section XI	Risk-Informed
LERF No Operator Action	6.41E-09	6.32E-09
• BDG	1.30E-10	1.30E-10
• CHS	1.25E-09	1.18E-09
• CI	7.30E-12	7.30E-12
• FWA	3.22E-13	3.22E-13
• MSS	1.32E-12	1.32E-12
• QSS	2.21E-11	1.96E-12
• RCS	2.62E-09	2.62E-09
• RSS	1.63E-12	1.63E-12
• SIS	2.38E-09	2.37E-09
• SSR	8.39E-12	8.39E-12
LERF with Operator Action	4.52E-09	4.36E-09
• BDG	1.24E-10	1.24E-10
• CHS	1.46E-11	9.81E-12
• CI	7.30E-12	7.30E-12
• MSS	2.45E-12	2.45E-12
• QSS	1.89E-11	4.89E-13
• RCS	2.62E-09	2.62E-09
• RSS	1.45E-12	1.45E-12
• SIS	1.73E-09	1.60E-09
• SSR	1.45E-12	1.45E-12

4. IMPLEMENTATION AND MONITORING PROGRAM

Upon approval of the RI-ISI program, procedures that comply with the guidelines described in the WCAP will be prepared to implement and monitor the program. The new program will be integrated into the existing ASME Section XI interval. No changes to the Update Final Safety Analysis Report are necessary for program implementation.

The applicable aspects of the Code not affected by this change would be retained, such as examination methods, acceptance guidelines, pressure testing, corrective measures, documentation requirements, and quality control requirements. Existing ASME Section XI program-implementing procedures would be retained and would be modified to address the RI-ISI process, as appropriate. Additionally the procedures will be modified to include the high safety significant locations in the program requirements regardless of their current ASME class.

The proposed monitoring and corrective action program will contain the following elements**:**

A. Identify
B. Characterize
C. (1) Evaluate, determine the cause and extent of the condition identified
   (2) Evaluate, develop a corrective action plan or plans
D. Decide
E. Implement
F. Monitor
G. Trend

The RI-ISI program is a living program requiring feedback of new relevant information to ensure the appropriate identification of high safety significant piping locations. As a minimum, risk ranking of piping segments will be reviewed and adjusted on an ASME period basis. Significant changes may require more frequent adjustment as directed by NRC bulletin or Generic Letter requirements, or by plant specific feedback.

5. PROPOSED ISI PROGRAM PLAN CHANGE

A comparison between the RI-ISI program and the current ASME Section XI program requirements for piping is given in Table 5-1. An identification of piping segments that are part of plant augmented programs is also included in Table 5-1.

The plant will be performing examinations on elements not currently required by ASME Section XI. An example of these additional examinations is provided below.

- The ASME Section XI Code does not require examination of piping less than 3/8-inch wall thickness on Class 2 piping greater than 4-inch nominal pipe size (NPS). The welds are counted for percentage requirements, but not examined by NDE. The RI-ISI program will require examination in this population of welds. Examples where the risk informed process requires examination and the Code did not are the suction lines to the charging pumps.

The initial program will be started in the inspection period current at the time of program approval. For example, the second (of three) inspection periods of the current 10-year inspection interval for BV2 ends on April 29, 2005. If the program is approved such that a refueling outage remains in the second period, 66% of the required RI-ISI examinations will be performed by the end of the current inspection interval.

Table 5-1

STRUCTURAL ELEMENT SELECTION (SES)
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS

System	High Safety Significant Segments (No. of HSS in Augmented Program / Total No. of Segments in Aug. Program)	Degradation Mechanism(s)	Safety Class	ASME Code Exam Category	Total Weld Count (Welds requiring Volumetric (Vol) and Surface (Sur))		ASME XI Program Examinations		RI-ISI[a]		
					Vol & Sur	Sur only	Vol & Sur	Sur only	SES Matrix Region	No. of Aug. Program Segments	Number of Exam Locations
BDG	0 (0/24)	FAC/TF	Class 2	N/A	0	0	0	0	3	24[c]	0
CHS	33 (0/0)	TF/VF, TF	Class 1	B-J	4	369	3	57	2, 3, 4	0	0
			Class 2	C-F-1	343	315	26	27		0	19 + 14[b]
CI	0 (0/0)	FAC/TF, TF	Class 2	N/A	0	0	0	0	4	0	0
DAS	0 (0/0)	TF	Class 1	B-J	0	36	0	24	4	0	0
FWA	0 (0/57)	FAC/TF	Class 2	C-F-2	56	0	9	0	3	57[c]	0
GNS	0 (0/0)	TF	Class 2	N/A	0	0	0	0	4	0	0
HCS	0 (0/0)	TF	Class 2	N/A	0	0	0	0	4	0	0
MSS	8 (8/53)	FAC/TF	Class 2	C-F-2	136	3	17	0	1B, 3	53[c]	8[e]
QSS	15 (0/0)	TF, VF	Class 2	C-F-1	200	0	16	0	1A, 1B, 2, 4	0	15 + 4[b]
RCS	26 (0/0)	SCC/TF, SCC/TF/VF/SS, TF	Class 1	B-F	18	0	18	0	2, 4	0	26 + 2[d]
			Class 1	B-J	217	350	57	136		0	
RHS	1 (0/0)	TF/SCC, TF	Class 1	B-J	22	6	7	2	2, 4	0	1
			Class 2	C-F-1	283	0	23	0		0	0
RSS	0 (0/0)	TF	Class 2	C-F-1	199	0	16	0	4	0	0
SIS	24 (0/0)	TF	Class 1	B-J	222	157	43	14	2, 4	0	0
			Class 2	C-F-1	934	200	71	17		0	19 + 5[b]

Table 5-1

STRUCTURAL ELEMENT SELECTION (SES)
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS

System	High Safety Significant Segments (No. of HSS in Augmented Program / Total No. of Segments in Aug. Program)	Degradation Mechanism(s)	Safety Class	ASME Code Exam Category	Total Weld Count (Welds requiring Volumetric (Vol) and Surface (Sur))		ASME XI Program Examinations		RI-ISI[a]		
					Vol & Sur	Sur only	Vol & Sur	Sur only	SES Matrix Region	No. of Aug. Program Segments	Number of Exam Locations
SSR	0 (0/0)	TF	Class 1	N/A	0	0	0	0	4	0	0
			Class 2	N/A	0	0	0	0		0	0
TOTAL	107 (8 / 134)	FAC/TF, TF, SCC/TF, SCC/TF/VF TF/ VF, WH, VF	Class 1		483	918	128	233		0	27 NDE + 2 VIS
			Class 2		2151	518	181	44			61 NDE + 25 VIS
			Total		2634	1436	309	277			88 NDE + 27 VIS

Table 5-1

STRUCTURAL ELEMENT SELECTION (SES)
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS

System	High Safety Significant Segments (No. of HSS in Augmented Program / Total No. of Segments in Aug. Program)	Degradation Mechanism(s)	Safety Class	ASME Code Exam Category	Total Weld Count (Welds requiring Volumetric (Vol) and Surface (Sur))		ASME XI Program Examinations		RI-ISI[a]		
					Vol & Sur	Sur only	Vol & Sur	Sur only	SES Matrix Region	No. of Aug. Program Segments	Number of Exam Locations

Summary: Current ASME Section XI selects a total of 586 welds while the proposed RI-ISI program selects a total of 88 welds (115 - 27 visual exams), which results in a 85% reduction.

Degradation Mechanisms: VF – Vibratory Fatigue; TF – Thermal Fatigue; FAC – Flow-Assisted Corrosion, SCC – Stress Corrosion Cracking; Strip/Strat – Striping/Stratification

Notes for Table 5-1
a. System pressure test requirements and VT-2 visual examinations shall continue in all ASME Code Class systems.
b. VT-2 examination at one location within segment.
c. Augmented programs for erosion-corrosion and/or high energy line break continue.
d. Examinations added for change in risk considerations (Total of two segments - RCS).
e. Included also in augmented program for erosion-corrosion and/or high energy line break. Augmented program continues.

6. SUMMARY OF RESULTS AND CONCLUSIONS

A partial scope (Class1 and Class 2) risk-informed ISI application has been completed for BV2. Upon review of the proposed risk-informed ISI examination program given in Table 5-1, an appropriate number of examinations are proposed for the high safety significant segments across the Class 1 and Class 2 portions of the plant piping systems. Resources to perform examinations currently required by ASME Section XI in the Class 1 and Class 2 portions of the plant piping systems, though reduced, are distributed to address the greatest amount of risk within the scope. Thus, the change in risk principle of Regulatory Guide 1.174 is maintained. The examinations performed will address specific damage mechanisms postulated for the selected locations through appropriate examination selection. Additional examinations will be performed when evidence of degradation is discovered.

The plant is designed to ASME III for all Class 1 piping. There is an improved level of fatigue analysis and operating condition scrutiny for the ASME III NB-3600 design as compared to other plants. This results in a much larger percentage of its Class 1 piping constructed with butt welds as opposed to socket welds and more detailed information is available for input to the estimation of the failure probability.

From a risk perspective, the PRA dominant accident sequences include station blackout, small LOCAs and steam generator tube rupture events with loss of core cooling from the secondary side.

For the RI-ISI program, appropriate sensitivity and uncertainty evaluations have been performed to address variations in piping failure probabilities and PRA consequence values along with consideration of deterministic insights to assure that all high safety significant piping segments have been identified.

As a risk-informed application, this submittal meets the intent and principles of Regulatory Guide 1.174.

7. REFERENCES/DOCUMENTATION

WCAP-14572, Revision 1-NP-A, “Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report,” February 1999

WCAP-14572, Revision 1-NP-A, Supplement 1, “Westinghouse Structural Reliability and Risk Assessment (SRRA) Model for Piping Risk-Informed Inservice inspection,” February 1999

U.S. Nuclear Regulatory Commission, “An Approach Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” Regulatory Guide 1.174, July 1998.

<u>Supporting Onsite Documentation</u>

1. Segment Definition Calculations:
    1. 10080-DMC-0139, Revision 0, 4/17/02, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Quench Spray System”.
    2. 10080-DMC-0140, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Recirculation Spray System, Revision 0, 4/17/02”.

3. 10080-DMC-0141, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Reactor Plant Vents and Drains System, Revision 0, 4/17/02”.
4. 10080-DMC-0142, Revision 1, 4/17/02, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Chemical and Volume Control System”.
5. 10080-DMC-0143, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Steam Generator Blowdown System, Revision 0, 4/17/02”.
6. 10080-DMC-0144, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Steam Generator Feedwater System, Revision 0, 4/17/02”.
7. 10080-DMC-0145, Revision 0, 4/17/02, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Main Steam System”.
8. 10800-DMC-0146, Revision 0, 3/30/02, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Reactor Plant Sampling System”.
9. 10080-DMC-0147, Revision 0, 3/27/02, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Post DBA Hydrogen Control System”
10. 10080-DMC-0148, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Gaseous Nitrogen System, Revision 0, 3/30/02”
11. 10800-DMC-0149, Revision 1, 3/30/02, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Containment Isolation System”.
12. 10800-DMC-0150, 3/16/02, Revision 0, “Beaver Valley Unit 2 RI-ISI Segment definition for the Reactor Coolant System
13. 10800-DMC-0151, 3/25/02, Revision 0, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Residual Heat Removal System”
14. 10800-DMC-0152, 3/20/02, Revision 0, “Beaver Valley Unit 2 RI-ISI Segment Definition for the Safety Injection System

2. 10080-DMC-0724, Revision 0, 10/15/01, “Beaver Valley Unit 2 Risk-Informed ISI Indirect (Spatial) Consequence Evaluation
3. 10080- DMC-0730, Revision 1, 1/22/02, “Risk-Informed In-Service Inspection (RI-ISI) PRA Calculation For Unit 2 RI-ISI Systems”.
4. SRRA Documentation**:**
   1. 10080-DMC-0153, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Reactor Plant Vents and Drains System.
   2. 10080-DMC-0154, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Containment Depressurization System (QSS).
   3. 10080-DMC-0155, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Containment Depressurization System (RSS).
   4. 10080-DMC-0156, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Residual Heat Removal (RHS) System.
   5. 10080-DMC-0157, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Steam Generator Blowdown (BDG) System.
   6. 10080-DMC-0158, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for Reactor Coolant (RCS) System.
   7. 10080-DMC-0159, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Steam Generator Feedwater (FWA) System.
   8. 10080-DMC-0160, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Chemical and Volume Control (CHS) System.

9. 10080-DMC-0161, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Main Steam (MSS) System.
10. 10080-DMC-0162, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Post-DBA Hydrogen Control (HCS) System.
11. 10080-DMC-0163, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Safety Injection (SIS) System.
12. 10080-DMC-0164, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Containment Isolation System.
13. 10080-DMC-0165, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Reactor Plant Sampling System (SSR).
14. 10080-DMC-0168, Revision 0, “Risk-Informed InService Inspection (RI-ISI) Structural Reliability and Risk Assessment (SRRA) for the Gaseous Nitrogen System (GNS).

5. CN-RRA-01-31, Revision 0 “Beaver Valley Power Stations 1 & 2 Risk Evaluation for RI-ISI”, 2/20/02
6. CN-RRA-02-18, Revision 0, “Beaver Valley Power Station 2 Perdue Evaluation”, 3/27/02
7. CN-RRA-02-30, Revision 0, “Beaver Valley Power Station 2 Change In Risk Evaluation”, 3/27/02
8. Expert Panel Data:
   8.1 FENOC-01-356, “Expert Panel Review Materials”, 12/17/01
   8.2 ND1MLM:0184, “Risk Informed ISI Expert Panel”, 1/2/02
   8.3 FENOC-02-45, “RI-ISI Expert Panel Action Item Resolutions”, 1/28/02
   8.4 ND1MLM:0214, “Results of the Expert Panel Review of Comment Resolution”, 3/11/02
   8.5 CN-RRA-02-12, Revision 0, “Beaver Valley Power Station 2 Expert Panel Database”, 5/16/02

ATTACHMENT 3

FirstEnergy Nuclear Operating Company
Beaver Valley Power Station, Unit No. 1 and No. 2

Risk-Informed Inservice Inspection Piping Program

Comparison of BVPS-1 and BVPS-2 Postulated Consequences by System

(Reference Table 3.3-1 of Attachments 1 and 2)

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Steam Generator Blowdown System (BD/BDG)	Direct effects: Reactor Trip (RT) and Partial Loss of Main Feedwater (PLMFW) Initiating Events. Loss of Auxiliary Feedwater, Dedicated Auxiliary Feedwater and Main Feedwater to Steam Generators. Loss of the containment pressure boundary. Indirect effects: None	Direct effects: Reactor Trip (RT), Partial Loss of Main Feedwater (PLMFW), Steam Line Break Upstream of MSIV Initiating Events. Loss of Auxiliary Feedwater and Main Feedwater to Steam Generators. Loss of the containment pressure boundary. Indirect effects: None	Unit 2 has a 2” line connected to the S/G steam space, which was modeled as a steam line break. The Unit 2 startup feedwater pump is modeled as part of the Main Feedwater System.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Chemical and Volume Control System (CH/CHS)	Direct effects: Reactor Trip (RT), Small or Medium LOCA Initiating Events. The following consequences would occur due to pipe failures in various locations within the CH System. • Loss of High Head and Low Head Safety Injection • Loss of recirculation • Loss of seal injection to one or more RCP seals • Loss of one or both charging trains • Loss of Letdown • Loss of normal and emergency boration • Loss of Refueling Water Storage Tank inventory outside of containment • Loss of Containment Sump Inventory outside of containment • Loss of the containment pressure boundary. Indirect effects: Indirect effects for jet impingement/spray were identified that disabled the alternate charging flow path, the alternate train of high head injection/recirculation, or a RCP seal injection flow path.	Direct effects: Reactor Trip (RT), Small or Medium LOCA Initiating Events. The following consequences would occur due to pipe failures in various locations within the CHS. • Loss of High Head and Low Head Safety Injection • Loss of recirculation • Loss of seal injection to one or more RCP seals • Loss of one or both charging trains • Loss of Letdown • Loss of normal and emergency boration • Loss of Refueling Water Storage Tank inventory outside of containment • Loss of Containment Sump Inventory outside of containment • Loss of the containment pressure boundary. Indirect effects: Indirect effects for spray were identified that disabled the system function of alternate trains of CHS and an SIS train.	No differences for direct effects. Indirect effects are similar, both units have spray effects which disable the alternate charging/HHSI train.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Containment Isolation System (CI)	Direct effects: Loss of Primary Component Cooling, Containment Instrumentation Air, and Station Instrument Air Initiating Events. Loss of RCP thermal barrier and motor cooling. Loss of cooling to the RHR heat exchangers. Loss of chilled water system. Loss of river water flow to recirculation spray heat exchanger. Loss of the containment pressure boundary. Indirect effects: Indirect effects for spray were identified that would disable a charging flow control valve and a reactor system drain train.	Direct effects: Loss of Primary Component Cooling Initiating Event. Loss of RCP thermal barrier and motor cooling. Loss of cooling to the RHR heat exchangers. Loss of the containment pressure boundary. Indirect effects: None	Unit 1 Cont. Instrument Air is inside containment and cross ties to Station Air, therefore there is a cont. isolation failure which fails them. The Unit 2 chilled water system is not in the Unit 2 PRA. The Unit 1 Recirc Spray heat exchanger is inside containment & subject to cont. isolation failure. Difference in indirect effects due to plant arrangement differences.
Reactor Plant Drains and Vents Systems (DV/DAS)	Direct effects: Loss of the containment pressure boundary. Indirect effects: None	Direct effects: Loss of the containment pressure boundary. Indirect effects: None	No differences.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Steam Generator Feedwater System (FW/FWA)	Direct effects: Reactor Trip (RT), Partial Loss of Main Feedwater (PLMFW), and Total Loss of Main Feedwater (TLMFW) Initiating Events. Loss of main, auxiliary, or dedicated auxiliary feedwater to one or more steam generators. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.	Direct effects: Reactor Trip (RT), Partial Loss of Main Feedwater (PLMFW), Main Feedwater Line Break (MFWLB), and Total Loss of Main Feedwater (TLMFW) Initiating Events. Loss of main or auxiliary feedwater to one or more steam generators. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.	Main Feedwater Line Break is not in the current Unit 1 PRA model, it was treated as part of the Total Loss of Main Feedwater events. The Unit 2 Main Feedwater model includes the startup feedwater pump.
Gaseous Nitrogen System (GNS)		Direct effects: Loss of accumulator injection. Loss of the containment pressure boundary. Indirect effects: None	The Unit 1 nitrogen supply to the accumulators is designated as part of the Safety Injection System, the Unit 2 supply is designated as a separate GNS system.
Hydrogen Control System (HY/HCS)	Direct effects: Loss of the containment pressure boundary. Indirect effects: None	Direct effects: Loss of the containment pressure boundary. Indirect effects: None	No differences.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Main Steam System (MS/MSS)	Direct effects: Steam Line Break Inside Containment (SLBI), Steam Line Break Outside Containment (SLBD), and Steam Line Break in Common RHR Valve Line (SLBC) Initiating Events. Loss of Main Feedwater to all steam generators due to MFW Pump trip on SI signal. Loss of Main Feedwater, Auxiliary Feedwater and Dedicated Auxiliary Feedwater to faulted steam generator. Failure of one or more of the steam supply paths to the Turbine Driven Auxiliary Feedwater Pump. Disabled atmospheric steam dump valves on the faulted steam generators. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.	Direct effects: Steam Line Break Upstream of MSIV (SLBI), Steam Line Break Downstream of MSIV (SLBD), and Steam Line Break in Common RHR Valve Line (SLBC) Initiating Events. Loss of Main Feedwater to all steam generators due to MFW pump trip on SI signal. Failure of one or more of the steam supply paths to the Turbine Driven Auxiliary Feedwater Pump. Disable the atmospheric steam dump valves on the faulted steam generator. Loss of the containment pressure boundary. Indirect effects: Potential impacts were included as part of the direct effects assessment.	The initiator names and descriptions between the 2 PRA models are slightly different but are for identical events. Unit 2 has a cavitating venturi in the Aux Feedwater System which limits flow to the faulted steam generator.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Quench Spray System (QS/QSS)	Direct effects: Loss of RWST inventory outside containment. Loss of one or both trains of QS, LHSI / HHSI injection and recirculation. Loss of the containment pressure boundary. Indirect effects: Quench Spray impacts are addressed as part of the direct effects assessment.	Direct effects: Loss of RWST inventory outside containment. Loss of one or both trains of QSS, LHSI / HHSI injection and Recirculation. Loss of the containment pressure boundary. Indirect effects: Jet Impingement/Spray and Flooding fails Auxiliary Feedwater pumps, Low Head SI pump, Recirculation Spray pump or Quench Spray pump.	No differences in the direct effects. Differences in indirect effects due to differences in plant arrangement.
Reactor Coolant System (RC/RCS)	Direct effects: Depending upon location and size, segment failure will result in either a small, medium, or large break LOCA. In addition, failures of other functions such as hot or cold leg injection or recirculation, loss of RHR, loss of pressurizer spray, and loss of letdown or charging could occur. Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RC piping failures were evaluated and mitigated as part of design basis activities.	Direct effects: Depending upon location and size, segment failure will result in either a small, medium, or large break LOCA. In addition, failures of other functions such as hot or cold leg injection or recirculation, loss of RHR, loss of pressurizer spray, and loss of letdown or charging could occur. Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RCS piping failures were evaluated and mitigated as part of design basis activities.	No differences.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Residual Heat Removal System (RH/RHS)	Direct effects: Small, medium, or large LOCA Initiating Events. Depending upon location, segment failure (without operator action) results in a loss of one or more of the following functions: • Loss of RHR • Loss of HHSI and LHSI hot leg recirculation • Loss of accumulator injection Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RH piping failures were evaluated and mitigated as part of design basis activities.	Direct effects: Small, medium, or large LOCA Initiating Events. Depending upon location, segment failure (without operator action) results in a loss of one or more of the following functions: • Loss of RHR • Loss of HHSI and LHSI hot leg recirculation • Loss of accumulator injection Operator action, in most cases, would isolate the faulted RHS train. Loss of the containment pressure boundary. Indirect effects: A review of all of the impacts of RHS piping failures were evaluated and mitigated as part of design basis activities.	The Unit 2 RHR system design allows isolation of 1 train.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Recirculation Spray System (RS/RSS)	Direct effects: Loss of containment sump inventory due to the failure outside containment. Failure will eventually lead to failure of all RS and all HHSI/LHSI recirculation. Loss of containment and decay heat removal. Loss of the containment pressure boundary. Indirect effects: None	Direct effects: Loss of containment sump inventory due to the failure outside containment. Failure will eventually lead to failure of all RSS and all HHSI/LHSI recirculation. Loss of containment and decay heat removal. Loss of the containment pressure boundary. Indirect effects: None	No differences

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Safety Injection System (SI/SIS)	Direct effects: Reactor Trip (RT); Small, Medium or Large LOCA Initiating Events. Depending upon location, segment failure can result in a loss of one or more of the following functions: • Loss of accumulator injection • High Pressure Injection • High Pressure Recirculation • Low Pressure Injection • Low Pressure Recirculation • Loss of RWST inventory outside containment, LHSI. HHSI, QS, and RS Pumps for Injection and Recirculation Loss of the containment pressure boundary. Indirect effects: Indirect effects for spray were identified that would disable a charging system valve.	Direct effects: Reactor Trip (RT); Small, Medium or Large LOCA Initiating Events. Depending upon location, segment failure can result in a loss of one or more of the following functions: • Loss of accumulator injection • High Pressure Injection • High Pressure Recirculation • Low Pressure Injection • Low Pressure Recirculation • Loss of RWST inventory outside containment, HHSI, LHSI, QSS, and RSS Pumps for Injection and Recirculation Loss of the containment pressure boundary. Indirect effects: None	No differences in direct effects. Difference in indirect effects due to differences in plant arrangement.

System	Summary of Consequences for Unit 1	Summary of Consequences for Unit 2	Differences
Sampling System (SS/SSR)	Direct effects: Reactor Trip (RT) Initiating Event. Loss of affected accumulator. Loss of the containment pressure boundary. Indirect effects: None	Direct effects: Reactor Trip (RT), Partial Loss of Main Feedwater (PLMFW). Depending upon location segment failure can result in a loss of one of the following: • Loss of auxiliary feedwater to one steam generator • Loss of affected accumulator • Loss of one charging pump and boration flow to other operable pumps. Loss of the containment pressure boundary. Indirect effects: None	Unit 2 has a 2” sample line from the blowdown system (steam generator liquid space) which results in a PLMFW and loss of AFW to 1 steam generator. Unit 2 has a 1/2” sample line on the charging pump discharge, Unit 1 has a 3/8” line.