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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Edwin I. Hatch Nuclear Plant Units 1 and 2
License Amendment Request to Revise
Technical Specification Section 5.5.12 for Permanent
Extension of Type A and Type C Leak Rate Test Frequencies
Responses to NRC Requests for Additional Information

Ladies and Gentlemen:

On July 1, 2016, Southern Nuclear Operating Company (SNC) submitted a license amendment request to permanently extend the test intervals for the Hatch Technical Specifications (TS) 5.5.12 Primary Containment Leakage Rate Testing Program. On December 5, 2016, the Nuclear Regulatory Commission (NRC) staff, upon a determination that additional information was needed to complete its review, issued a letter requesting that SNC respond to their enclosed questions (RAIs) within 60 days. Enclosed are SNC responses to the RAIs.

This letter contains no NRC commitments. If you have any questions, please contact Ken McElroy at 205.992.7369.

Mr. C. R. Pierce states that he is the Regulatory Affairs Director for SNC, is authorized to execute this oath on behalf of SNC and, to the best of his knowledge and belief, the facts set forth in this letter are true.

Respectfully submitted,

C. R. Pierce

C. R. Pierce
Regulatory Affairs Director

crp/efb/lac

Sworn to and subscribed before me this 10 *day of* February *, 2017.*

Laura L. Crofts
Notary Public

My commission expires: 10-8-2017

Enclosure:
Responses to NRC Requests for Additional Information

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Enclosure

RAI 1

Section 3.2.4, "ILRT History," of the July 1, 2016, application, contains two tables, "Table 3.2.4-1, Unit 1 Type A ILRT History," and "Table 3.2.4-2, Unit 2 Type A ILRT History." Both tables provide test dates and leakage rates about the historical ILRTs performed for HNP, Unit Nos. 1 and 2. All historical ILRT leakage rate values contained in both Table 3.2.4-1 and Table 3.2.4-2 are below the limits of both TS 5.5.12 and TS 5.5.12.a. However, the test pressure values for the six HNP, Unit Nos. 1 and 2, historical ILRT as-found leakage rates were not included.

Section 9.2.3, "Extended Test Intervals," of NEI 94-01, Revision 2 and 2-A, states, in part:

Acceptable performance history is defined as successful completion of two consecutive periodic Type A tests where the calculated performance leakage rate was less than 1.0 La [the maximum allowable Type A test leakage rate at Pa, where Pa equals the calculated peak containment internal pressure related to the design-basis loss-of-coolant accident].

Section 3.2.11, "Type A Test Pressure," of ANSI/ANS 56.8-1994, "American National Standard for Containment System Leakage Testing Requirements" (ADAMS Accession No. ML 11327 A024), states, in part:

The Type A test pressure shall not be less than 0.96Pac [calculated peak accident containment internal pressure, also defined as Pa above] nor exceed Pd [containment design pressure].

Please provide the test pressure values for the two most recent as-found Type A tests for HNP, Unit Nos. 1 and 2, and state if they satisfy the requirements of Section 9.2.3 of NEI 94-01, Revision 2 and 2-A, and Section 3.2.11 of ANS 56.8-1994.

SNC Response

SNC provides the following response to RAI 1:

ILRT Test Pressures Employed During The Two Most Recent Type A Tests					
Test Date	**ILRT Test Pressure, P_a (psig)**	**Minimum Test Pressure (psig)**	**Final Type A Test Pressure (psig)**	**Maximum Allowed Test Pressure, (psig)**	**Peak Test Pressure (psig)**
Unit 1					
April 1993	60.0	59.0 [3]	59.0732	60	59.7
March 2008	50.8 [1]	48.8 [4]	52.243	56	52.7

ILRT Test Pressures Employed During The Two Most Recent Type A Tests					
Test Date	**ILRT Test Pressure, P_a (psig)**	**Minimum Test Pressure (psig)**	**Final Type A Test Pressure (psig)**	**Maximum Allowed Test Pressure, (psig)**	**Peak Test Pressure (psig)**
Unit 2					
November 1995	45.5	44.5 [3]	46.3168	47.5	46.5
March 2009	47.3 [2]	45.4 [4]	47.957	49.3	48.53

Notes:	
1.	On May 28, 2004, the NRC issued Amendment No. 241 to Renewed Facility Operating License DPR-57 for HNP, Unit 1. This amendment changed the peak calculated post-accident primary containment internal pressure values, Pa, in TS Section 5.5.12. The peak calculated primary containment internal pressure for the design basis LOCA, Pa, was increased to 50.8 psig from 49.6 psig.
2.	On May 28, 2004, the NRC issued Amendment 184 to Renewed Facility Operating License NPF-5 for HNP, Unit 2. This amendment changed the peak calculated post-accident primary containment internal pressure values, Pa, in TS Section 5.5.12. The peak calculated primary containment internal pressure for the design basis LOCA, Pa, was increased to 47.3 psig from 45.5 psig.
3.	ANSI/ANS 56.8-1978, 1987, Section 3.2.2, "...shall not exceed the containment design pressure and shall not be permitted to fall more than 1 psi below Pa, for the duration of the test."
4.	ANSI/ANS 56.8-1994, Section 3.2.11, " The Type A test pressure shall not be less than 0.96Pac nor exceed Pd.

RAI 2

Section 9.1.2, "Test Interval," of NEI 94-01, Revision 3-A, states that extensions in test intervals are allowed based upon two consecutive, periodic successful Type A tests. At the time of the two previous Type A tests, the guidance of NEI 94-01, Revision 0 (ADAMS Accession No. ML 11327 A025), was used to determine if the tests were considered successful. NEI 94-01, Revision 0, Section 9.2.3, "Extended Test Intervals," states, in part:

For purposes of determining an extended test interval, the performance leakage rate is determined by summing the UCL [upper confidence limit] (determined by containment leakage rate testing methodology described in ANSI/ANS 56.8-

1994) with As-left MNPLR [minimum pathway leakage rate] leakage rates for penetrations in service, isolated or not lined up in their accident position (i.e., drained and vented to containment atmosphere) prior to a Type A test. In addition, any leakage pathways that were isolated during performance of the test because of excessive leakage must be factored into the performance determination. If the leakage can be determined by a local leakage rate test, the as-found MNPLR for that leakage path must also be added to the Type A UCL. If the leakage cannot be determined by local leakage rate testing, the performance criteria for the Type A test are not met.

Please provide the following information for (1) the HNP, Unit No. 1, Type A tests performed in March 2008 and April 1993; and (2) the HNP, Unit No. 2, Type A tests performed in March 2009 and November 1995:

(a) The as-left minimum pathway leakage rate (MNPLR) for all Type B and Type C pathways that were in service, isolated, or not lined up in their test position (i.e., drained and vented to containment atmosphere) prior to performing the Type A test.

(b) List all the pathways and the associated leakage rate that contribute to MNPLR in item (a), above.

(c) The performance leakage rate (PLR) (= UCL + MNPLR).

(d) Determine if the "as-found" Type A test meets the performance criterion by showing if PLR $\leq$ maximum allowable Type A test leakage rate at P_a (i.e., L_a).

(e) Cite the calculation method for UCL (i.e., mass point method from ANSI/ANS-56.8-1994, total time, or point to point, etc.).

SNC Response

SNC provides the following response to RAI 2:

HNP ILRT Test Results Verification of Current Extended ILRT Intervals					
	a.	**b.**	**c.**	**d.**	**e.**
Test Date	**weight % / day**	**Note No.**	**weight % / day**	**(Note 5) weight % / day**	**Test Method / Data Analysis Techniques**
Unit 1					
April 1993	0.0020 (530.0 sccm)	1.	0.3628 (95% UCL = 0.3608)	0.7465 Limit 1.2000	Absolute / BN-TOP-1 Total Time

HNP ILRT Test Results Verification of Current Extended ILRT Intervals					
	a.	b.	c.	d.	e.
Test Date	**weight % / day**	**Note No.**	**weight % / day**	**(Note 5) weight % / day**	**Test Method / Data Analysis Techniques**
March 2008	0.0673 (16,143 sccm)	2.	0.3404 (95% UCL = 0.3401)	0.7558 Limit 1.2000	Absolute / BN-TOP-1 Total Time
Unit 2					
November 1995	0.0030 (165.0 accm)	3.	0.3175 (95% UCL = 0.3145)	0.6707 Limit 1.2000	Absolute / BN-TOP-1 Total Time
March 2009	0.0417 (9234 sccm)	4.	0.1000 (95% UCL = 0.2183)	0.5422 Limit 1.2000	Absolute / BN-TOP-1 Total Time

Notes:			
	Penetration	Reason for Penalty	As-left leakage (SCCM)
1.	X-14	Not Vented	20.0
	X-20, 44	Not Vented	303.0
	X-42	Not Vented	0.0
	X-23, 24	Not Vented	197.0
	X-221A	Not Vented	0.0
	X-221C	Not Vented	10.0
2.	X-100A	Not Vented	3
	X-100B	Not Vented	5
	X-100D	Not Vented	0
	X-100E	Not Vented	5
	X-100G/H	Not Vented	0
	X-100I/J	Not Vented	0
	X-101A	Not Vented	1
	X-101B	Not Vented	10
	X-101CV	Not Vented	1
	X-101D	Not Vented	8
	X-101E	Not Vented	5
	X-101F	Not Vented	5
	X-102A	Not Vented	5
	X-103A	Not Vented	1007
	X-104A	Not Vented	1
	X-104B	Not Vented	1
	X-104C	Not Vented	0
	X-104F	Not Vented	19

Notes:			
	Penetration	Reason for Penalty	As-left leakage (SCCM)
	X-104G	Not Vented	5
	X-104H	Not Vented	5
	X-105A	Not Vented	5
	X-106B	Not Vented	5
	X-202	Not Vented	0
	X-7A	Not Vented	0
	X-7B	Not Vented	0
	X-7C	Not Vented	253
	X-7D	Not Vented	31
	X-8	Not Vented	0
	X-10	Not Vented	0
	X-11	Not Vented	85
	X-12	Not Vented	21
	X-14	Not Vented	0
	X-18	Not Vented	0
	X-19	Not Vented	0
	X-20, 44	Not Vented	442
	X-23, 24	Not Vented	18
	X-27A	Not Vented	8
	X-28A	Not Vented	0
	X-31F	Not Vented	1
	X-35A	Not Vented	3
	X-35B	Not Vented	0
	X-35C	Not Vented	39
	X-35D	Not Vented	5
	X-35E	Not Vented	5
	X-40C(F)	Not Vented	1
	X-42	Not Vented	29
	X-46	Not Vented	5
	X-52F	Not Vented	0
	X-59F	Not Vented	0
	X-206A	Not Vented	5
	X-221A	Not Vented	24
	X-221C	Not Vented	7
	X-28F, 31D, 217	Isolated	93
	X-26, 34E, 220	Isolated	206
	X-27A, 33D	Isolated	21
	ECCS (see Note Below)	Not Vented	1072*
	* Highest As-Left minimum pathway between Division 1 ECCS (X-13A, 16A, 39A, 211A) versus Division 2 ECCS (X-138, 168, 398, 2118)		
3.	X-3	Not Vented	0.0
	X-14	Not Vented	70.0
	X-22	Not Vented	0.0
	X-42	Not Vented	0.0

Notes:			
	Penetration	Reason for Penalty	As-left leakage (SCCM)
	X-51C	Not Vented	0.0
	X-64	Not Vented	0.0
	X-23, 24	Not Vented	60.0
	X-47, 48	Not Vented	35.0
	X-217A	Not Vented	0.0
	X-221B	Not Vented	0.0
	X-221C	Not Vented	0.0
4.	X-3	Not Vented	1
	X-8	Not Vented and Drained	3
	X-10	Not Vented and Drained	3
	X-11	Not Vented and Drained	3
	X-12	Not Vented and Drained	20
	X-13A	Not Vented and Drained	140
	X-13B	Not Vented and Drained	434
	X-14	Not Vented	0
	X-16A	Not Vented and Drained	20
	X-16B	Not Vented and Drained	5
	X-17	Not Vented and Drained	5
	X-18	Not Vented and Drained	5
	X-19	Not Vented and Drained	5
	X-21	Not Vented	8
	X-22	Not Vented	1
	X-23, 24	Not Vented	77
	X-27C	Not Vented	3
	X-28	Not Vented	5
	X-34C	Not Vented	2
	X-35A	Not Vented	17
	X-35B	Not Vented	5
	X-35C	Not Vented	5
	X-35D	Not Vented	6
	X-39A	Not Vented and Drained	383
	X-39B	Not Vented and Drained	26
	X-41	Not Vented and Drained	5
	X-42	Not Vented	1
	X-45D	Not Vented and Drained	5
	X-46	Not Vented and Drained	5
	X-47, 48	Not Vented and Drained	230
	X-51C	Not Vented	8
	X-55	Not Vented and Drained	0
	X-57C	Not Vented	5
	X-60A	Not Vented	8
	X-60B	Not Vented	5
	X-62	Not Vented	11
	X-64	Not Vented	12
	X-69	Not Vented	18

Notes:			
	Penetration	Reason for Penalty	As-left leakage (SCCM)
	X-100A	Not Vented	5
	X-100B	Not Vented	5
	X-100D	Not Vented	13
	X-100E	Not Vented	14
	X-100G/H	Not Vented	5
	X-100I/J	Not Vented	5
	X-101A	Not Vented	7
	X-101B	Not Vented	5
	X-101C	Not Vented	8
	X-101D	Not Vented	4
	X-101E	Not Vented	0
	X-101F	Not Vented	2
	X-102A	Not Vented	9
	X-103A	Not Vented	5
	X-104A	Not Vented	0
	X-104B	Not Vented	0
	X-104C	Not Vented	9
	X-104F	Not Vented	5
	X-104G	Not Vented	13
	X-104H	Not Vented	16
	X-105A	Not Vented	87
	X-105C	Not Vented	257
	X-106A	Not Vented	8
	X-206C	Not Vented	5
	X-217A	Not Vented	0
	X-217B	Not Vented	0
	X-217C	Not Vented	5
	X-221B	Not Vented	4
	X-225A	Not Vented	5
	X-225B	Not Vented	5
	X-225C	Not Vented	5
	X-225D	Not Vented	5
	X-225E	Not Vented	5
	X-225F	Not Vented	5
	X-225G	Not Vented	5
	X-225H	Not Vented	5
	X-225J	Not Vented	5
	X-225K	Not Vented	5
	X-225L	Not Vented	5
	X-225M	Not Vented	5
	X-233	Not Vented	15
5.	The as-found leakage rate is calculated by adding the 95-percent UCL, the penalties for non-standard alignment, the adjustments for water level inventory, and the penetration minimum pathway improvements made during the local leakage rate testing program previous to the Type A test.		

RAI 3

Sections 10.2.1.4, "Corrective Action," and 10.2.3.4, "Corrective Action," of NEI 94-01, Revision 3-A, state, in part, that for unacceptable Type B and Type C test results, respectively:

... a cause determination should be performed and corrective actions identified that focus on those activities that can eliminate the identified cause of failure with appropriate steps to eliminate recurrence.

Please provide the following additional information about Table 3.4.5-1, "Unit 1 Type B and C LLRT Program Implementation Review," from the July 1, 2016, submittal:

(a) For the two local leak rate test (LLRT) failures during 1 RF26 (i.e., 2014) associated with Penetration 221A and Penetration 26, please provide additional information beyond that of table notes (1) and (2) about the corrective actions performed during 1 RF26 and the LLRT history of the CIVs associated with these two penetrations.

(b) Please provide information on 3 examples of repetitive failures of administrative limits for LLRTs associated with any HNP, Unit No. 1, Type B or Type C penetrations since 2006. Also, please provide the details of all corrective actions performed to prevent reoccurrence.

Please provide the following additional information about Table 3.4.5-2, "Unit 2 Type B and C LLRT Program Implementation Review," from the July 1, 2016, submittal.

(c) For the two LLRT failures during 2RF22 (i.e., 2013) associated with Penetration 41 and Penetration 26, and the LLRT failure during 2RF23 (i.e. 2015) associated with Penetration 225K, please provide additional information beyond table notes (1), (2), and (3) about the corrective actions performed during these two refueling outages and the LLRT history of the CIVs associated with these three penetrations.

(d) Please provide information on 3 examples of repetitive failures of the administrative limits for LLRTs associated with any HNP, Unit No. 2, Type B or Type C penetration since 2006. Also, please provide details of all corrective actions performed to prevent reoccurrence.

SNC Response

SNC provides the following response to RAI 3:

Response to RAI 3 a)

Valve E41-F111

During 1R26 in 2014, Valve 1E41-F111 on Penetration 221A could not be brought to test pressure due to leakage through the seat of the valve. Per engineering request, a set of data was recorded at less than prescribed test pressure. At 47.5 psig measured leakage was 185,244 sccm. The administrative limit for allowable leakage is 275 sccm at 54 psig. This was not a penetration failure because the other series valve was tested satisfactorily.

Upon disassembly of valve, the wedge and seats were found to be unsatisfactory. Specifically, the stellite facing of the valve wedge had broken off the wedge on the downstream side. According to the vendor, possible causes of the de-laminating of the stellite facing were a) downstream cracking of the hard facing due to gradual degradation or b) insufficient pre-heat temperature before hard face deposit on that side of the wedge during fabrication.

Based on a review of work history, this valve was tested during 1R25 (the previous 2012 outage), and the valve passed initial LLRT. This valve was operated properly, and there is no indication that the 1R26 failure was due to inadequate vendor parts. Based on a review of work orders (WO) documenting the maintenance performed in February 2012, there was no indication that the failure was due to inadequate maintenance.

The valve was repaired by replacing the wedge with a new one machined to fit along with minor lapping of the seat rings. The new wedge was made of solid stellite to prevent the failure mechanism experienced of the stellite facing separating from the wedge body. An as-left LLRT was performed after repairs were made which yielded a leakage of 867 sccm at a pressure of 53.97, which is above the administrative limit of 275 sccm. However, because the results in conjunction with the leakage of all other Type B and Type C Tests were significantly less than the Technical Specification requirement of 163,392 sccm, SNC concluded that the leakage for 1E41-F111 (1-221A-C2) was acceptable until further work performed in the following outage (1R27) in 2016.

During 1R27 in 2016, the leakage was again above the administrative limit, so the valve was scheduled for replacement in accordance with documented corrective actions. As-left leakage evaluations for LLRT administrative test failures have been performed and documented in condition reports. See the LLRT history table below at the end of the RAI-3 a) response.

Valve 1T48-F335B

During 1R26 in 2014, Valve 1T48-F335B on Penetration 26 failed LLRT testing. Per the LLRT schedule, the valve that was supposed to be tested was the 1T48-F334B. However, during pressurization to perform the test, 1T48-F335B failed to hold pressure and exhibited gross leakage. Per the LLRT history, 1T48-F335B had not failed an LLRT since at least 1994. Based on the LLRT history, the valve was considered a good performer and not anticipated a candidate for failure. SNC rebuilt the valve internals and a review concluded that excessive wear and tear (aging degradation) was the main cause of failure. Consequently, the valve was fully refurbished with new gaskets, packing, and actuator diaphragm.

To prevent recurrence, preventative maintenance tasks (PMs) were written for diagnostic testing and valve refurbishment.

During 1R27 in 2016, the valve successfully passed the LLRT. See historical data in the table below.

LLRT History – RAI 3 a)					
Date	**Observed**	**Acceptance**	**Date**	**Observed**	**Acceptance**
1T48-F335B			**1E41-F111**		
10/6/94	0 accm	120 accm	9/24/94	126 accm	60 accm
3/28/96	0 accm	120 accm	10/4/94	0 accm	60 accm
10/28/97	0 accm	120 accm	3/28/96	0 accm	60 accm
10/6/00	21 accm	120 accm	10/31/97	0 accm	60 accm
3/30/02	0 accm	120 accm	3/26/99	43 accm	60 accm
4/8/02	31 accm	120 accm	10/12/00	0 accm	60 accm
2/20/04	21 accm	120 accm	3/29/02	5 accm	60 accm
2/24/06	21 accm	120 accm	2/24/04	55 accm	60 accm
2/26/06	21 accm	120 accm	2/24/06	42 accm	60 accm
2/12/08	0 accm	120 accm	2/20/08	34 accm	60 accm
2/25/12	2 sccm	575 sccm	2/23/12	170 sccm	275 sccm
2/14/14	Infinity	575 sccm	2/11/14	185244 sccm	275 sccm
2/28/14	0 sccm	575 sccm	2/28/14	867 sccm	275 sccm
2/9/16	80 sccm	575 sccm	2/18/16	7,400 sccm	275 sccm
2/23/16	57 sccm	575 sccm	2/24/16	936 sccm	275 sccm

Response to RAI 3 b)

Valve 1G31-F203

During 1R24 in 2010, valve 1G31-F203, RWCU return to feedwater check valve, failed to meet the acceptance criteria of < 600 accm leakage when tested at 54 psig. Measured leakage was > 60,000 accm with a max attainable test pressure of 27 psig. The valve failure did not by itself constitute a containment penetration failure; however, this component required repair and retest prior to Unit 1 startup. The seat was found washed out, with a disc hitting hard on one side and the

spring bent. The valve was repaired and new components were installed, including a diffuser, spring, disc and gasket.

The 1G31-F039 and 1G31-F203 valves are both 3" flanged nozzle check valves manufactured by Enertech. They have the same form, fit, and function. The 1G31-F039 valve was originally the only check valve in the line that discharges to the feedwater system. The 1G31F203 valve was added per DCR 82-85 during 1984 due to the feedwater check nozzle cracking. The 1G31-F039 and 1G31-F203 valves were later replaced with flanged nozzle check valves per MDC 99-16 and MDC 93-5065 to eliminate repetitive LLRT failures. These MDCs also changed the valve orientation in the line from horizontal to vertical.
The 1G31-F039 valve has not failed LLRT since 1999 when the valve was replaced with the flanged nozzle check valve. The 1G31-F203 check valve had numerous LLRT failures since the new check valve was installed in 1994.

The 1G31-F203 valve LLRT failures represent an adverse trend because this valve has failed the LLRT test since 2000 with each instance documenting the disc and inbody seat damage. A summary of the 2000-2008 maintenance records follows:

- 1/9/2000: WO1000326601 – The 1E41-F006 &1G31-F203 LLRT initial testing exceeded the procedural limit of 600 accm by leaking at 3,000 accm. The disc and the inbody seat were found damaged. Also, the disc stem and stem guide on the diffuser were found worn as well. The disc, diffuser, and various other components were replaced. The inbody seat was machined and repaired.

- 3/30/2002: WO10201101 - During LLRT testing, check valve 1G31-F203 failed to meet acceptance criteria in 42SV-TET-001-1S by not checking to hold pressure and flow. The valve was found with damage to the disc and the inbody seat. The valve was replaced with a new check valve.

- 2/24/2004: WO1040395901- During LLRT testing on check valve 1G31-F203, the as-found leakage was outside the procedural acceptable limits of 300 accm by leaking 1900 accm. The disc and inbody seat were found damaged and repaired to place the valve back in service.

- 2/14/2008: WO1080355801- While performing 42SV-TET-001-1, 1E41-F006/1G31-F203 exceeded the procedural leakage limit of 600 accm. The total leakage observed was 1120 accm. The increased leakage was determined to be the result of normal in-service degradation associated with wear of the valve internal components. The valve was replaced.

At this time, because the 1G31-F203 valve experienced disc and inbody seat damage every outage since 2000, SNC determined that the damage was likely

due to the elbow configuration of the piping to the valve causing turbulent flow through the line.

Potential causes, such as, improper installation and an improper application of the valve were determined to be unlikely. The 1G31-F039 (1999) and 1G31-F203 (1994) both were changed from a horizontal configuration to a vertical configuration during the modification that installed the new, flanged, nozzle check valve. The 1G31-F039 has not failed LLRT with the valve in this configuration; therefore, the 1G31-F203 check valve being improperly installed and oriented is not a likely cause of its LLRT failures. The vendor confirmed that the valve was designed for both orientations (vertical and horizontal).

The elbow configuration of the piping to the 1G31-F203 has approximately five elbows within a short distance for flow to travel immediately before reaching the valve. Turbulent flow occurs when the fluid traveling undergoes irregular fluctuations, or mixing. In turbulent flow, the speed of the fluid at a point is continuously undergoing changes in both magnitude and direction. The turbulent flow in the line is causing the valve to rock side to side causing disc chatter against the seat. The vendor recommends at least 3 feet of straight line piping directly to the valve for laminar flow. The 1G31-F203 valve has 1 foot and half of an inch of straight piping before the last elbow. The 1G31-F039 valve has one elbow within 3 feet of the valve, thus the laminar flow profile would coincide with the lack of LLRT failures.

Two possible solutions explored for resolving the LLRT failures were to modify the piping to ensure a less turbulent flow profile at the valve or to replace the existing elbows with a laminar flow vane elbow. Both of these options would provide a more laminar flow profile within the line and potentially improve the LLRT test results.

During 1R25 in 2012, valves 1E41-F006 and 1G31-F203 leakage was measured to be 1500 accm. The acceptable limit for this test was 203 accm. Diagnostics revealed through seat leakage on 1G31-F203. During diagnostics, it was discovered that leakage was <40 accm when testing only the 1B21-F032B and 1E41-F006. 1G31-F203 was replaced with a new valve in 1R25, through WO SNC369567.

At this time, the best solution for overcoming the problem with the numerous LLRT failures of the 1G31-F203 valve appeared to be a complete reconfiguration of the piping to provide a less turbulent flow path. However, the piping that leads up to the 1G31-F203 valve is class 1 safety-related piping. Rearranging the piping to accommodate a more laminar flow path for the valve would be very expensive, involve significant manpower resources during an outage, and would be a high dose activity. For these reasons, the Plant Health Committee did not recommend pursuing the design change. The current solution that SNC has in place is to keep replacement valves in stock and replace the valve (valve connection is flanged) if it fails LLRT during the outage.

SNC and the valve vendor continued investigating other solutions to the problems with the valve. The vendor recommended installing a lighter disc and spring in the valve to help alleviate the concern with the impact of the disc constantly fluttering during normal operation. Other valves designs were explored; however, the review only confirmed that the best type/design valve is already installed for the application. Finally, contingencies were put in place for full valve replacement as needed during future outages.

During 1R26 in 2014, valve 1G31-F203 passed the LLRT. The reported LLRT value was 30 accm, which is acceptable from its allowed leakage value of 203 accm. Valve 1G31-F203 was replaced with a new valve in 1R25. The 1G31F203 valve was not breached, repaired or replaced during 1R26.

During 1R27 in 2016, valve 1G31-F203 passed the LLRT.

Valve 1B21-F010A

During 1R24 in 2010, valve 1B21-F010A (penetration 9A), feedwater check valve, leakage was measured to be 8900 accm. The acceptable limit for this test is 203 accm. Diagnostics indicated through seat leakage. The other check valve for this penetration (1B21-F032A) was not tested at this time. Valve 1B21-F010A was disassembled, cleaned and inspected. The inspection revealed improper alignment caused by flawed dimensional tolerances of the hinge bushing, which determines the exact position of the disc. Recommended corrective actions included rebuilding the valve and replacing hinge pins with new pins with matching chamfer, lapping the in body seat, and fabricating/installing new stellite bushings. However, several attempts to rebuild 1B21-F010A (and other valves) were unsuccessful before repairs were completed. This delayed reactor start up and had a significant cost impact on the outage.

A new "one-vendor" strategy was developed and implemented to increase accountability and expertise and to ensure the maintenance on these valves is thoroughly understood, planned, and implemented in such a way to assure excellent equipment reliability. New valves were ordered for the smaller nozzle check valves so that should a valve fail LLRT, a replacement valve would be readily available.

During 1R25 in 2012, valve 1B21-F010A leakage was measured to be >10,000 accm. The acceptable limit for this test is 203 accm. Diagnostics revealed through seat leakage. Diagnostics further established that leakage was 9000 accm at 39 psig (< test pressure).

A review of the LLRT history showed that Unit 1 feedwater check valves routinely passed LLRT testing until 2010. Because of the failures in 2010 and 2012, the valve was replaced.

During 1R26 in 2014, valve 1B21-F010A failed to meet acceptance criteria of less than 203 accm at test pressure of 71-74 psig. Measured leakage was > 10,000

accm (highest range of instrument) at 51 psig. This valve required repair and retest prior to the Unit 1 startup.

Per procedure 51GMMNT-055-0, the recommended side-to-side tolerance of hinge pins is .010 - .050. Upon investigation, the actual side-to-side movement was found to be 0.123. Additionally it was discovered that the disc was all the way to one side of the valve. It was also discovered that the back of the disc was hitting on the valve body and not the actual stop.

Per the vendor recommendation, a bushing was installed as shown on drawing S53494. Rough areas in valve body and back of the disc were smoothed out. The aforementioned corrective actions ensured that the bushing will center the disc with the in-body seats and allow disc to open up to the stop correctly. An as-left LLRT test was performed on 2/18/14. The observed leakage was recorded at 20 accm. The administrative leakage for the valve is 203 accm.

During 1R27 in 2016, valve 1B21-F010A feedwater check valve LLRT results were successful with leakage recorded at 50 accm.

Response to RAI 3 c)

Valve 2B31-F019

During 2RF22 in 2013, valve 2B31-F019 associated with Penetration 41 failed the as-found LLRT. Diagnostic testing was performed, and SNC determined that the cause was leakage through the seat. The observed leakage was 280 sccm with an administrative limit of 150 sccm. A work order was issued to repair the valve. This was not a penetration failure because the other series valve was tested satisfactorily. Based on a review of the LLRT history, the valve had been a good performer and had not failed an LLRT since 1997.

The most cause of the test failure was valve aging degradation due to normal wear and tear. The valve was rebuilt and retested three weeks later and had an as-left leakage of 2 sccm with an administrative limit of 150 sccm. The valve LLRT history is included in the table below at the end of this response to RAI 3c).

Valve 2T48-F319 & 2T48-F320

During 2RF22 in 2013, valves 2T48-F319 & 2T48-F320 associated with Penetration 26 both failed to meet their allowable leakage limit of 4,850 sccm. The valve failures resulted in a failure of the associated vent purge return Penetration 26.

After the failure of valve 2T48-F319 during the as-found LLRT test, SNC investigated and found the valve was not sealing correctly. T-ring (sealing seat) and O-rings were replaced and the valve reinstalled and retested. When valves 2T48-F319 and 2T48-F320 were re-tested, the leakage was 76,220 sccm; which is greater than the allowable leakage of 4850 sccm. Further diagnostic investigation determined that the leakage was this time due to valve 2T48-F320.

SNC investigated and found the woodruff key and shaft keyway were worn causing the valve travel to be inconsistent. The key was replaced and a different keyway was used. The T-ring (sealing seat) and O-rings were replaced and the valve reinstalled. The penetration was retested and passed as-left LLRT testing with 0 sccm recorded leakage. SNC performed extent-of-condition reviews and PM adjustments accordingly. The LLRT history for both valves is included in the table below at the end of this response to RAI 3c).

Valve 2T48-342D

During 2RF23 in 2015, valve 2T48-F342D associated with Penetration 225K would not reach test pressure during LLRT testing and the leakage rate could not be quantified. After troubleshooting, SNC discovered that a flexible metal braided hose outside containment was severed and leaking. The hose was likely damaged by a physical impact, possibly while the scaffolding was being built. A work order was generated and the hose was replaced.

The valve LLRT histories are included in the table below:

LLRT History					
Date	**Observed**	**Acceptance**	**Date**	**Observed**	**Acceptance**
2B31-F019			**2T48-F319 and 2T48-F320**		
3/25/97	0 accm	30 accm	3/19/97	20 accm	1,080 accm
3/14/00	0 accm	30 accm	4/2/97	0 accm	1,080 accm
3/29/00	0 accm	30 accm	9/11/98	20 accm	1,080 accm
9/25/01	0 accm	30 accm	9/28/98	20 accm	1,080 accm
2/13/05	0 accm	30 accm	3/5/00	16,654 accm	1,080 accm
2/20/05	0 accm	30 accm	3/27/00	30 accm	1,080 accm
2/13/09	19 accm	30 accm	9/26/01	0 accm	1,080 accm
2/16/13	280 sccm	150 sccm	10/15/01	20 accm	1,080 accm
3/9/13	2 sccm	150 sccm	3/3/03	9,317 accm	1,080 accm
2/13/15	3 sccm	150 sccm	3/14/03	21 accm	1,080 accm
2T48-F342D			2/11/05	0 accm	1,080 accm
3/21/97	0	50 accm	3/4/05	20 accm	1,080 accm
9/10/98	0	50 accm	2/15/07	Infinity	1,080 accm
10/5/98	0	50 accm	3/5/07	20 accm	1,080 accm
3/15/00	20	50 accm	2/23/09	35 accm	1,080 accm
9/20/01	0	50 accm	3/12/09	13 accm	1,080 accm
3/6/03	0	50 accm	4/5/11	1,382 sccm	4,850 sccm
3/20/03	0	50 accm	4/5/11	1,420 sccm	4,850 sccm
2/12/05	0	50 accm	3/4/13	Infinite	4,850 sccm
2/15/07	0	50 accm	3/4/13	Infinite	4,850 sccm
2/19/09	5	50 accm	3/14/13	0 sccm	4,850 sccm
3/6/09	5	50 accm	2/18/15	8 sccm	4,850 sccm
4/8/11	5	50 accm			

2/24/13	7 sccm	250 sccm	
3/8/15	61 sccm	250 sccm	

Response to RAI 3 d)

Valve 2T48-F309 and Valve 2T48-F324

During 2R20 in 2009, the valves 2T48-F309 and 2T48-F324 failed LLRT testing. These are 18" Fisher type 9200 butterfly valves tested simultaneously per 42SV-TET-001-2 with the D006 flange. The first as-found test documented the leakage rate to be infinity (CR 2009101594). The leakage was attributed to the F309 valve by the program engineer. The F309 valve was repaired on WO 2070622901 and retested. The valve failed the retest. The F324 was tested and failed with a leakage rate of 13,284 accm (CR 2009103004). This valve was adjusted for retesting and passed. The F309 was again repaired on WO 2090641801 and passed. Final testing showed a total of 143 accm for these valves.

The F309 valve had failed LLRT testing the previous two outages in 2005 and 2007. Further investigation of repeat failures on this valve had shown that adjusting actuator stops is common as there is slight drift over time. In March 2007 the F309 valve was also discovered with excessive wear to the actuator yoke and keyway. The valve actuator was adjusted and the valve passed the 2007 LLRT re-test. The repairs for excessive wear were delayed until the 2009 outage. In 2009, once the F309 valve actuator yoke was repaired and the stops for both valves were adjusted, the valves were re-tested and passed. Because the actuator stops were out of adjustment, the valve was not properly seated.

During 2R21 in 2011, LLRT was performed on primary containment penetration 2T23X205. This penetration failed its leak test because of gross leak by of both primary containment isolation valves (PCIVs) 2T48-F309 (inboard) and 2T48-F324 (outboard). During the as-found LLRT, condition report (CR) 2011104286 documented that adequate air pressure could not be achieved for the leak test. The highest pressure read on the LLRT test panel was no greater than 33 psig; 49-51 psig is the required test pressure. As soon as the test air was isolated, pressure bled off the torus vent header rapidly. All leak-likely connections were investigated, and inboard isolation valve 2T48-F309 was found to be the only valve leaking by initially. SNC repaired the valves under WO# 2110444101 and reinstalled the valve so an LLRT could be performed on the penetration. On 4/16/2011, the penetration was re-tested and the required test air pressure could not be achieved a second time. Again, all leak-likely connections were checked, and outboard isolation valve 2T48-F324 was found to be the source of the leakage this time. The highest test pressure that could be achieved was 39 psig. Both valves' as-found leakage was greater than the overall allowable leakage required by the HNP-2 technical specification for primary containment.

Review of maintenance history revealed that the 2T48-F309 valve had a negative trend in as-found LLRT testing. Since 2005, the valve had failed its administrative allowed leak rate test every outage. Prior to 2005, the LLRT

history showed the valve failed to meet the administrative leak rate limit of 1080 accm three times (1991, 1994, and 2001) since 1985. The following is a work history of the failures identified during previous outages:

- During 2R18 in 2005, PM WO# 2050506601 rebuilt the valve's Bettis Actuator, replacing wearable parts on 2/21/2005. This followed a failed LLRT on valve 2T48F309.
- During 2R18 in 2005, following a failed LLRT on valve 2T48-F309, SNC replaced the t-ring, o-rings, and re-centered the disc in the valve body.
- During 2R19 in 2007, following a failed LLRT on valve 2T48-F309, SNC determined that the valve disc was not centered within the valve body and also identified that the shaft / key had excessive wear. A CR documented the degraded condition, but the parts were not replaced.
- During 2R20 in 2009, following a failed LLRT on valve 2T48-F309, SNC rebuilt the actuator and replaced the actuator yoke and stem. The valve pins, t-ring, and o-rings were also replaced. After failing the re-test, the valve was removed a second time to adjust the t-ring under WO 2070622901.

Review of maintenance history revealed that the 2T48-F324 valve failed leak rate test for the penetration three times since 1985 (2001, 2009, and 2011).

An investigation was performed during the 2R20 outage in 2009 to determine the cause of the failed LLRT which concluded with adjustments to the valve travel.

In 2011, valves 2T48-F324 and 2T48-F309 both failed LLRT testing resulting in a failure of the Primary Containment Penetration. SNC performed an enhanced apparent cause determination (EACD). The EACD identified that the F324 failures were likely due to damage caused by the disc over traveling. Investigation found 2 apparent causes for this issue. One was that the actuator stops were not being adjusted properly and the second was that the over traveling may be contributed to wear of the actuator. One corrective action added guidance to PM procedure 52PM-T48-013-0. The second corrective action was to perform WO 2110681601 to rebuild the actuator.

During 2R22 in 2013, the as-found LLRT measured leakage on 2T48-F309 and 2T48-F324 was greater than 42SV-TET-001-2 allowable limit of 4850 sccm. The diagnostics determined the leakage path to be through the seat of 2T48-F324, with no detectable leakage through the seat of 2T48-F309. All flanges, bonnets, and valve packings within the tested boundary were snoop checked and no leakage detected.
This failure was prior to all of the corrective actions being completed from the EACD. The actuator rebuild and new PM procedure enhancements were performed during 2R22 after this failure.

During 2R23 in 2015, valve 2T48-F309 failed as-found LLRT Testing. Diagnostic trouble shooting was performed, and the valve was repaired under work order SNC636674. The seating ring was replaced in addition to several o-rings as needed due to disassembly and reassembly. On 3/4/15, the post maintenance LLRT results for 2T48-F309 were documented on 42SV-TET-001-2 as "zero leakage".

Valve 2B21-F010A and 2B21-F010B

During 2R20 in 2009, feedwater check valves 2B21-F010A, 2B21- F010B and 2B21-F077A failed LLRTs. Both 2B21-F010A/B failed to meet acceptance criteria of less than 280 accm leakage during LLRT testing. The 2B21-F077A also failed LLRT, resulting in a failure of the 9A penetration. An investigation was performed which included a review of the LLRT history for these valves.

The 2B21-F010A/B valves had a poor LLRT performance history. The 2B21-F010A valve had not passed LLRT since November 1995 and 2B21-F010B had not passed LLRT since November 1994. The original design of the 2B21-F010A/B valves was modified in March 1997 to replace the existing hinge pins, hinge pin retainers and gaskets with adjustable hinge pin kits for ease of maintenance. Since the hinge pin replacements in 1997, both valves had failed LLRT every outage.

Inadequate design of the 2B21 F010A/B adjustable hinge pins allowed lateral movement of the disc along the axis of the hinge pins as well as undesired rotation of the pins. This was corrected by Minor Design Change (MDC) 2090395802 implemented during the 2009 2R20 outage, which installed bushings in the hinge pins to prevent lateral movement and installed dowel pins to prevent rotational movement.

Lack of trending LLRT failures from one outage to the next was identified as a weakness. Corrective actions included revising the LLRT procedure to implement analysis of LLRT failures at the end of each outage - an aggregate analysis as well as a component specific analysis. Effectiveness reviews and apparent cause determinations (ACDs) were programmatically added for LLRT repetitive failures.

Corrective actions were completed to repair the valves following the 2009 outage and the valves were scheduled for replacement during the next outage:
2B21-F010A (action completed per WO 2090383401)
2B21-F010B (action completed per WO 2090354101).

During 2R21 in 2011, valves 2B21F010A and 2B21F010B feedwater check valves failed LLRT when tested per 42SV-TET-001-2. The valves tested at greater than 10,000 accm (max range of instrumentation) at 35.5 psig pressure. The valves had already been scheduled for replacement during the 2R21 outage and would require retest prior to startup. 2B21F010A and 2B21F010B were replaced. LLRTs were performed. The 2B21-F010A passed its LLRT with a leakage of 135 accm and 2B21-F010B passed its LLRT with a leakage of 90 accm.

During 2R22 in 2013, 2B21F010A and 2B21F010B feedwater check valves LLRTs were satisfactory. The 2B21-F010A passed its LLRT with a leakage of 50 accm and 2B21-F010B passed its LLRT with a leakage of 40 accm.

During 2R23 in 2015, 2B21F010A and 2B21F010B feedwater check valves LLRTs were performed. The 2B21-F010B passed its LLRT with a leakage of 45 accm and 2B21-F010A failed its LLRT - could not establish test pressure while performing 42SV-TET-001-2 for 2B21F010A FW check valve.

2B21F010A was disassembled and inspected. The valve disc had a gap of .020 at the bottom. The bearing and shaft were replaced. 2B21-F010A passed its post maintenance LLRT with a leakage of 150 accm.

RAI 4

In Appendix J, Option B, LLRT program, the percentage of Type B or Type C components on repetitive frequencies can vary depending on the maintenance program and corrective action process.

(a) Please provide the total number (i.e., population) and percentage of the total number of HNP, Unit Nos. 1 and 2, Type B tested components currently on a 120-month extended performance-based test interval. Provide the numbers for HNP, Unit Nos. 1 and 2, separately.

(b) Please provide the total number (i.e., population) and percentage of that total number of HNP, Unit Nos. 1 and 2, Type C CIVs currently on a 60-month extended performance-based test interval. Provide the numbers for HNP, Unit Nos. 1 and 2, separately.

(c) Please discuss how the percentages reported in (a) and (b) above support an extended test interval of up to 75 months for both HNP, Unit Nos. 1 and 2, Type C tested CIVs in accordance with the guidance of NEI 94-01, Revision 3-A.

SNC Response

SNC provides the following response to RAI 4:

		Total Number Components	% On Extended Interval
a)	Unit 1 Type B	143	71
	Unit 2 Type B	149	79
b)	Unit 1 Type C	124	53
	Unit 2 Type C	133	57

c) SNC believes that the percentages reported above, the small number of components exhibiting repeat failures, and the improving trends and/or large

margins shown in the July 1, 2016 LAR submittal in Tables 3.4.4-1 and 3.4.4-2 are indicative of an effective maintenance and corrective action program and support an extended interval of up to 75 months for both HNP, Unit Nos. 1 and 2, Type C tested CIVs that have met the performance criteria of NEI 94-01 Section 11.3.1, including past component performance, service, design, safety impact and cause determination, and that are subject to programmatic controls, including the additional considerations of as-found tests, schedule, and review presented in NEI 94-01 Section 11.3.2.

RAI 5

In Table 3.7.1-1, "NEI 94-01, Revision 2-A, Limitations and Conditions," of the July 1, 2016, application, the fourth Limitation/Condition states:

The licensee addresses any tests and inspections performed following major modifications to the containment structure, as applicable. (Refer to SE [safety evaluation] Section 3.1.4.).

The HNP Response for HNP, Unit Nos. 1 and Unit 2, states:

There are no major modifications planned.

The above HNP Response is forward looking with respect to plans for any future HNP, Unit Nos. 1 and 2, containment modifications. However, both HNP, Unit Nos. 1 and 2, containments have been in service for greater than 35 years. Sections 3.1.2, "Suppression Chamber"; 3.1.3, "Vent System"; and 3.5.2, "IN [Information Notice] 88-82, Torus Shells with Corrosion and Degraded Coatings in BWR [Boiling-Water Reactor] Containments," of the application all briefly describe modifications to the HNP, Unit Nos. 1 and 2, containments.

Please provide additional historical information (i.e., a synopsis) about any modifications, and the subsequent associated post-modification testing, to the HNP, Unit Nos. 1 and 2, containments, since the most recent ILRTs, and demonstrate consistency with the guidance of NEI 94-01, Revision 2-A, SE Section 3.1.4.

SNC Response

SNC provides the following response to RAI 5:

On the basis of NEI 94-01 Rev. 2-A SER Section 3.1.4, "Major and Minor Containment Repairs and Modifications," HNP has not made any modifications to primary containment since the last ILRT was performed on either unit, i.e., March 2008 for Unit 1 and March 2009 for Unit 2. HNP staff reviewed Section 3.1.4 of the NEI 94-01 Rev 2-A SER and discussed same with the Repair/Replacement (R&R) engineer who performed a search for related R&R plans and found none. This was also discussed with the Inservice Inspection (ISI) engineer, and again, no evidence of any modifications was identified. Hatch plant staff is confident that there are no modifications to report.

A review of the activities associated with NRC issued Order EA-13-109, "Issuance of Order to Modifying Licenses with Regard to Reliable Hardened Containment Vents Capable of Operation Under Severe Accidents," June 6, 2013, revealed that the modifications involved the addition of Accumulator Tanks, N2 Bottles and a Rupture Disk outboard of the Containment Isolation Valves on the Drywell and Wetwell purge lines. None of these activities impacted containment leakage integrity.

RAI 6

Section 4.2.6 of Electric Power Research Institute (EPRI) Report 1018243, "Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals," states that, "[p]lants that rely on containment overpressure for net positive suction head (NPSH) for emergency core cooling system (ECCS) injection for certain accident sequences may experience an increase in CDF [Core Damage Frequency]," therefore, requiring a risk assessment. EPRI Report 1018243 is the NRC-approved version of EPRI Report 1009325, Revision 2.

(a) Section 5.2.4 of EPRI Report 1018243 includes guidance on performing this risk assessment and provides the following examples of accident scenarios to be considered:

- LOCA [loss-of-coolant accident] scenarios where the initial containment pressurization helps to satisfy the NPSH requirements for early injection in BWRs or PWR [pressurized-water reactor] sump recirculation

- Total loss of containment heat removal scenarios where gradual containment pressurization helps to satisfy the NPSH requirements for long term use of an injection system from a source inside of containment. ..

The July 1, 2016, LAR only discusses large-break LOCA initiators, which is not necessarily the same as a LOCA scenario (when the LOCA is not the initiating event). LOCA initiators are a relatively small contributor to the internal events CDF. However, other internal events initiators (e.g., transients) or conditions (e.g., station blackout) could result in a consequential LOCA. Please explain how all the accident scenarios that could impact NPSH for the ECCS pumps were considered.

(b) The LAR summarizes the results of Modular Accident Analysis Program (MAAP) analysis modeling a "large break LOCA (28" diameter recirculation line break)" and concludes, in part, that:

... loss of ECCS NPSH is not a concern for sequences where one or more trains of RHR [residual heat removal] containment heat removal operate.

Discuss any key assumptions in the MAAP analysis that may be non-conservative and impact the loss of NPSH assessment.

(c) For LOCA scenarios with containment heat removal unavailable, the licensee states that containment overpressure will lead to containment failure and that in the HNP, Unit Nos. 1 and 2, probabilistic risk assessment (PRA), containment failure is assumed to result in a loss of ECCS core injection. The licensee concludes that a preexisting containment failure (as might be detected by the Type A ILRT), resulting in the loss of adequate NPSH to the ECCS pumps, would have the same result as containment overpressure, and therefore, there is no change in CDF. Overstating the contribution of containment overpressure to the loss of ECCS appears to be non-conservative with respect to the change in CDF for this application. Please provide justification for the assumption that containment overpressure leads to containment failure and a loss of ECCS, or provide an updated risk analysis.

SNC Response

SNC provides the following response to RAI 6:

Response to RAI 6(a)

The Hatch PRA contains a basic event, NPSHLOSSPROB, which models the failure of ECCS if the containment is accidently or purposely de-pressurized. This basic event is applied to a wide range of accident sequences (e.g., consequential LOCAs, not just Large LOCA initiators).
CDF could be impacted due to an increase in the likelihood for a loss of containment overpressure resulting from a pre-existing leak from containment and loss of heat removal systems. Per the EPRI guidance, as a first order estimate of the impact, it can be assumed that the EPRI Class 3b contribution would lead to loss of containment overpressure. For the Hatch PRA model, applying that guidance would mean that the current containment isolation failure logic can be increased by the Class 3b frequency at 15 years (i.e., 0.0023 * 5.0 = 0.0115) to estimate a bounding increase in CDF. With this increase applied to the loss of NPSH probability in the Hatch PRA model, the CDF increases from 7.57E-06 /yr to 8.12E-06 /yr representing an increase of 5.47E-07 /yr. The bounding analysis is in the very small range (CDF <1E-06 /yr) per RG-1.174, and as such the focus on the LERF figure of merit for this application is appropriate for Hatch.

Response to RAI 6(b)

The ILRT analysis documents four MAAP calculations in Table 2.0-1 of Attachment 3 which were performed to assess the maximum torus temperature achieved for a large break LOCA when a single train of RHR containment heat removal is operating. The purpose of these MAAP calculations is to demonstrate that with a single train of containment heat removal operating the torus temperature remains well below 211°F, a temperature level that can impact

NPSH requirements for U1 components. Large LOCA scenarios are used as a bounding estimate due to the largest impact on torus temperature. The four MAAP calculations demonstrate that for a range of containment leakage rates, the torus temperature remains below approximately 181°F. These MAAP calculations were reviewed for potential inputs and key assumptions that could potentially be non-conservative and impact the loss of NPSH assessment.

Key assumptions & inputs examined include:

1. RHR containment heat removal start time – For each MAAP calculation torus cooling is initiated when the torus temperature level rises above 100°F. This is consistent with the current Hatch EOPs.
2. Initial torus water temperature – The initial torus temperature is conservatively set at 100°F, the highest temperature allowed without needing torus cooling.
3. Initial torus water inventory – The initial torus water level is set at a best-estimate height of 12.3 ft which is consistent with typical plant operation.
4. RHRSW temperature - The RHRSW river water temperature is assumed to be 95°F compared with the upper design limit is 97°F. The slight difference in temperature is considered negligible, and the 95°F value is judged to still be a conservative value for best estimate analysis.
5. Reactor Power level – MAAP assumes 100%, the highest rated core power level, for all calculations.
6. Large LOCA MAAP Modeling issues – MAAP is known to have some modeling deficiencies (e.g., potential for reverse flow not modeled) for Large LOCAs scenarios. These deficiencies only impact results in the early portion of the run (i.e., approximately first three minutes) prior to core recovery. These deficiencies do not impact the ILRT MAAP calculation results because the peak torus temperature is reached hours into each run.
7. Pump flow rates – All pump flow rates are based on best estimates of actual flow capabilities of all pumps.
8. MAAP NPSH calculation – MAAP evaluates (and will fail) injection sources based on NPSH requirements. The MAAP NPSH calculation includes control volume pressures and vertical heights (i.e., static head) but ignores flow losses (e.g., pipe friction and line losses). Ignoring pipe flow losses is non-conservative, but these losses are very small contributors in comparison to the factors included in the NPSH calculation. In the Hatch MAAP calculations, the NPSH margin available is large compared to the potential impact of line losses.

The above assumptions are considered to be either best estimate or conservative, except for the non-conservative modeling aspect associated with pipe flow losses (which is considered a negligible contributor). Based on the above, the MAAP calculations are judged to present a best estimate result for evaluating the potential loss of NPSH.

Response to RAI 6(c)

Without containment heat removal, Level 2 MAAP cases (Accident Class II) demonstrate that the containment pressure will increase and eventually reach the containment failure pressure in the 15 hour time frame. The Hatch Phenomenological Evaluation on Containment Overpressurization identifies that the drywell-to-torus vent line bellows located low in the Reactor Building are generally expected to be the most limiting structural element for the containment. A failure of the bellows would result in a release to the torus room and adjacent Reactor Building lower elevations. Per the containment evaluation, this release path would subject ECCS equipment components to harsh conditions and is assumed to preclude their use or repair. In the Hatch PRA, containment failure in the torus region is probabilistically estimated to occur 79% of the time. The remaining 21% of the time, the containment failure is postulated to occur in the drywell head area which would not be expected to fail ECCS components.

To estimate the potential impact associated with a containment overpressurization failure in the drywell head area that does not impact the ECCS injection, a CDF increase associated with a postulated loss of ECCS injection NPSH can be calculated as follows:

- CDF increase = 0.21 * (Class IIA frequency + Class IIL frequency)
- CDF increase = 0.21 * (3.39E-6/yr + 4.11E-10/yr)
- CDF increase = 7.12E-7/yr

This CDF increase is in the very small range (CDF <1E-06 /yr) per RG-1.174, and as such the focus on the LERF figure of merit for this application is appropriate for Hatch.

This postulated CDF increase is based on Accident Class II sequences. As identified in Section 6.3 (Non-Early Release Sensitivity) of the ILRT risk evaluation, Accident Class II sequences are non-early releases and therefore do not contribute to LERF. Therefore, none of this postulated CDF increase would contribute to the calculation of the EPRI Class 3a or 3b frequencies. Therefore, there would be no change to the calculated ILRT dose risk from EPRI Classes 3a and 3b, or to the EPRI Class 3b frequency (LERF) results.

RAI 7

In Section 4.2 of Attachment 3 to the LAR, the licensee discusses the CDF and large early release frequency values for HNP, Unit Nos. 1 and 2. The licensee further highlights a plant design difference in the feedwater injection lines where it concludes that the design difference will not impact the risk assessment for the ILRT interval, and that the Unit No. 1 model is representative of Unit No. 2 for the purposes of the ILRT risk assessment. Please provide a detailed discussion of the design differences between HNP, Unit No. 1, and HNP, Unit No. 2, that have significant impact on the CDF. Additionally, please provide a justification for concluding that the Unit No. 1 model is representative of Unit No. 2 for the

purposes of the ILRT risk assessment or provide the Unit No. 2 plant-specific confirmatory analysis.

SNC Response

SNC provides the following response to RAI 7:

Table 7-1 below presents a more detailed list of Hatch unit design differences and an assessment of their potential impact on the ILRT application. None of these design differences are found to impact the conclusions of the ILRT Risk Assessment.

As noted in the Section 4.2 of the ILRT Risk Assessment, the total FPIE CDF for Unit 1 bounds Unit 2 by approximately 1.5%. Because the ILRT methodology is highly based on total CDF, the ILRT results for Unit 1 are judged to bound those for Unit 2.

Table 7-1
Hatch Unit 1 and Unit 2 Design Differences Assessment

Design Differences in Unit 1 and Unit 2	ILRT Impact
The shared Main Control room ventilation is powered by Unit 1 components and the Unit 1 Service Air system.	Minor difference in unit design would increase Unit 2 dependency on Unit 1 systems. MCR cooling is modeled in the PRA, but it is a slowly developing event. Failure of Unit 2 power would not fail the MCR HVAC in the Unit 2 model and therefore use of the Unit 1 model is judged bounding. No impact on the ILRT results.
The 1B diesel is a shared diesel that is normally aligned to Unit 1.	Negligible impact on the Unit 2 model because a swap of the diesel is required. No impact on the ILRT results.
Unit 1 containment coolers are cooled by plant service water. Unit 2 containment coolers are cooled by the P64 chilled water system which is serviced by plant service water.	Negligible difference between the units. Failure of plant service water would have the same impact. Unit 2 containment coolers would be impacted by a failure of the P64 system. No impact on the ILRT results.

Table 7-1
Hatch Unit 1 and Unit 2 Design Differences Assessment

Design Differences in Unit 1 and Unit 2	ILRT Impact
Due to different piping routes the internal flooding analysis for each unit is different.	Internal flood only accounts for approximately 1% of CDF for both units. The Unit 2 Internal flooding contribution is lower than the Unit 1 internal flooding contribution. As such, the Unit 1 model is judged to conservatively bound the Unit 2 model. No impact on ILRT results.
Unit 2 has an extra set of low pressure feedwater heaters allowing a higher electrical output. Unit 2 requires three condensate booster pumps at 100% power while Unit 1 requires only two at 100% power.	The condensate booster pumps are not credited for most accident sequences and therefore the difference between the units is negligible. No impact on the ILRT results.
Unit 2 startup transformers are physically located in the Unit 1 low voltage switchyard.	The physical location of the transformers would have a negligible impact on the internal events PRA model. Impacts to the external events is considered negligible. Exposure to tornadoes, high winds, etc., would be the same for both units given that the startup transformers are located in the same area. No impact on the ILRT results.
Lower drywell and torus design temperature for Unit 1 of 281°F (versus 340°F for Unit 2).	Use of Unit 1 would be conservative because the Unit 2 containment is designed to withstand higher temperatures. No impact on the ILRT results.
Slight torus volume differences: Unit 1 Torus Free Volume = 112,900 ft^2 Unit 2 Torus Free Volume = 109,800 ft^2	The slight differences in torus volume are not considered significant for the PRA results. No impact on the ILRT results.
Additional pedestal sump in Unit 2.	No impact on the ILRT results.
Unit 1 credits containment overpressure for core spray and RHR pump operation. Unit 2 does not require containment overpressure for core spray or RHR pump operation.	Unit 1 is bounding for NPSH concerns. No impact on the ILRT results.

RAI 8

Section 5.8 of Attachment 3 to the LAR addresses the risk impact from external events for the ILRT extension.

(a) The risk estimates from all external hazards, except for seismic risk, is based on the results from the individual plant examination of external events (IPEEE). Since the IPEEE study was completed in 1995, please assess these external events for the current state of HNP and discuss the effect on the LAR.

(b) The LAR calculates an "external events multiplier" of 0.51 by dividing the external events CDF by the internal events CDF calculated during the individual plan examination (IPE). This multiplier is then applied to the internal events Class 3b frequency, which is estimated based on the current internal events PRA and has a much lower CDF estimate than the IPE. This approach underestimates the risk due to external events by at least an order of magnitude. Please justify your approach for using the "external events multiplier" or update your analysis to correctly capture the impact from external events.

SNC Response

SNC provides the following response to RAI 8:

Response to RAI 8(a)

Seismic

In August 2010, GI-199 was released by the NRC detailing the impact of seismic events on existing plants based on the revised seismic hazard curves from the USGS. Table D-1 of GI-199 shows the estimated seismic core damage frequency for Hatch 1 and 2 is 2.2E-6/yr using the weakest link model. In Section 5.8 of the Hatch ILRT risk assessment, the Seismic CDF was assumed to be equal to the Fire CDF value of 7.5E-6/yr, a factor of 3.4 higher than that estimated by the NRC for GI-199. Therefore, the seismic CDF input into the Hatch ILRT assessment has considerable margin compared to more recent data.

In Section 5.8 of the Hatch ILRT Risk Assessment, the Seismic CDF applied in the ILRT calculations was reduced by 70% (i.e., from 7.5E-6/yr to 2.25E-6/yr) based on the Peach Bottom (also a Mark I containment design) seismic evaluation that identified that the probability for early containment failure for seismically induced events is high (70% or higher). This same reduction factor would still apply for the newer Hatch seismic CDF value, thereby reducing the value applicable to the ILRT calculations to 6.6E-7/yr (i.e., 2.2E-6/yr * 0.3).

Hatch has a developed Seismic PRA (SPRA) model that was peer reviewed in November 2016. The seismic CDF for Unit 1[1] from the peer reviewed model of 3.08E-7/yr is over a factor of 24 lower than the estimated value used in the ILRT Risk Assessment and over a factor of seven lower than the estimation from GI-199. The seismic LERF for Unit 1 from the peer review model is 1.03E-7/yr, approximately 30% of seismic CDF. This LERF to CDF ratio supports the ILRT Risk Assessment estimation of reducing the seismic CDF impact by 70% to estimate seismic LERF. Use of the ILRT Risk Assessment seismic estimation or the GI-199 estimation conservatively bounds the seismic risk at Hatch.

Internal Fires

As stated in Section 5.8 of the Hatch ILRT Risk Assessment, Plant Hatch is developing a Fire PRA in support of the planned transition to NFPA 805. The development of the Hatch Fire PRA to the latest industry standards is still on-going. It is generally expected that the calculated Fire CDF of the under-development Fire PRA will exceed that of the IPEEE value of 7.5E-6/yr. The amount by which the Fire PRA CDF will increase is not known. This potential is evaluated in the response to RAI 8b.

Other External Hazards

An Evaluation of Other External Events (not including seismic, internal fire, and internal floods) was performed by SNC in 2013. An extensive review of information on the site region and plant design was made to identify all external events to be considered. The data in the IPEEE, UFSAR as well as other data was obtained and reviewed. Screening criteria were applied to identify the events that should be further examined for potential inclusion in the PRA. The application of initial screening criteria resulted in the need for further bounding analyses of seven external hazards:

1. Aircraft Impact
2. Extreme Winds and Tornadoes
3. External Flooding including Intense Local Precipitation
4. Industrial and Military Facility Accidents
5. Pipeline Accidents
6. Transportation Accidents
7. Turbine Generated Missiles

Bounding analyses of these seven hazards resulted in concluding that these external hazards do not pose a credible threat to Plant Hatch and do not need to be included in the PRA. This conclusion is consistent with the conclusion of the IPEEE.

Response to RAI 8(b)

The external event multiplier of 0.51 used in the ILRT LAR was developed using the ratio of the IPEEE era external event and internal event CDFs. CDF

[1] The seismic CDF and LERF results for Unit 2 are lower than the Unit 1 results; as such the Unit 1 seismic results bound the Unit 2 seismic risk.

estimates from the same era were used to develop the ratio based on the perspective that the underlying PRA models were comparable.

In response to RAI 8(b), the external event multiplier is recalculated using the ILRT LAR external event values and the current internal events CDF rather than the IPEEE internal events CDF. The external event multiplier is also calculated using the more recent seismic CDF estimate presented in RAI response 8(a).

Using the current internal events CDF and the ILRT LAR external events CDF values, the external event multiplier is calculated as follows:

- External Events Multiplier = External Events CDF/Internal Events CDF
- External Events CDF = Seismic CDF + Internal Fire CDF + High Winds CDF + External Flood CDF (as developed in Section 5.8 of Attachment 3 of the LAR)
- External Events CDF = 2.25E-6/yr + 7.5E-6/yr + 1.0E-6/yr + 1.0E-8/yr = 1.08E-5/yr
- Internal Events CDF = 7.57E-6/yr
- External Events Multiplier = 1.08E-5/yr / 7.57E-6/yr = **1.43**

Using this updated external events multiplier, LAR Attachment 3 Table 5.8-2 is updated as follows:

Table 5.8-2
(Updated Internal Events CDF)
HATCH CLASS 3b (LERF) AS A FUNCTION OF ILRT FREQUENCY FOR INTERNAL AND EXTERNAL EVENTS (INCLUDING AGE ADJUSTED STEEL CORROSION LIKELIHOOD)

	3b Frequency (3-per-10 yr ILRT)	3b Frequency (1-per-10 year ILRT)	3b Frequency (1-per-15 year ILRT)	LERF Increase(1)
Internal Events Contribution(2)	1.58E-08	5.29E-08	7.97E-08	6.39E-08
External Events Contribution (Internal Events x 1.43)	2.26E-08	7.56E-08	1.14E-07	9.14E-08
Combined (Internal + External)	3.84E-08	1.29E-07	1.94E-07	1.55E-07

(1) Associated with the change from the 3-per-10 year frequency to the proposed 1-per-15 year frequency.
(2) Values from Table 5.7-1 of the ILRT Risk Assessment

The results of using the higher external events multiplier based on the current internal events CDF shows a LERF increase of 1.55E-7/yr which is in the "small" impact for deltas of <1E-6/yr. Using the same external events multiplier the total

LERF is calculated to confirm that total LERF is <1E-5/yr as directed by RG 1.174, as follows:

PRA Metric	Frequency
Internal Events LERF	1.12E-06/yr
External Events LERF (Internal events LERF x 1.43)	1.60E-06/yr
Total LERF (Internal + External)	2.72E-06/yr

The results show a significant margin is available to the total LERF threshold of 1E-5/yr. For total LERF to exceed this threshold, an external events multiplier of 7.9 or greater would be required. The associated LERF increase would be 5.7E-7/yr (still in the "small" impact region). Holding all other external event values constant, the Fire PRA CDF could increase to a value of approximately 5.6E-5/yr to remain below the 1E-5/yr total LERF threshold.

As discussed in RAI Response 8(a), the seismic CDF estimate is lower per GI-199 than that used in the ILRT submittal. Using the lower seismic CDF value of 6.6E-7/yr, the calculations may be repeated as follows:

- External Events Multiplier = External Events CDF/Internal Events CDF
- External Events CDF = Seismic CDF + Internal Fire CDF + High Winds CDF + External Flood CDF
- External Events CDF = **6.6E-7/yr** + 7.5E-6/yr + 1.0E-6/yr + 1.0E-8/yr = 1.08E-5/yr
- Internal Events CDF = 7.57E-6/yr
- External Events Multiplier = 9.17E-6/yr / 7.57E-6/yr = **1.21**

LAR Attachment 3 Table 5.8-2, if updated to include the Seismic CDF, would be as follows:

Table 5.8-2
(Updated Internal Events CDF and Seismic CDF)
HATCH CLASS 3b (LERF) AS A FUNCTION OF ILRT FREQUENCY FOR INTERNAL AND EXTERNAL EVENTS (INCLUDING AGE ADJUSTED STEEL CORROSION LIKELIHOOD)

	3b Frequency (3-per-10 yr ILRT)	3b Frequency (1-per-10 year ILRT)	3b Frequency (1-per-15 year ILRT)	LERF Increase(3)
Internal Events Contribution(4)	1.58E-08	5.29E-08	7.97E-08	6.39E-08
External Events Contribution (Internal Events x 1.21)	1.91E-08	6.40E-08	9.64E-08	7.73E-08

Table 5.8-2 (Updated Internal Events CDF and Seismic CDF) HATCH CLASS 3b (LERF) AS A FUNCTION OF ILRT FREQUENCY FOR INTERNAL AND EXTERNAL EVENTS (INCLUDING AGE ADJUSTED STEEL CORROSION LIKELIHOOD)				
	3b Frequency (3-per-10 yr ILRT)	**3b Frequency (1-per-10 year ILRT)**	**3b Frequency (1-per-15 year ILRT)**	**LERF Increase[3]**
Combined (Internal + External)	3.49E-08	1.17E-07	1.76E-07	1.41E-07

[3] Associated with the change from the 3-per-10 year frequency to the proposed 1-per-15 year frequency.

[4] Values from Table 5.7-1 of the ILRT Risk Assessment

The results of using the higher external events multiplier based on the current internal events CDF and lower seismic CDF shows a LERF increase of 1.41E-7/yr which is in the "small" impact for deltas of <1E-6/yr. Using the same external events multiplier the total LERF is calculated to confirm that total LERF is <1E-5/yr as directed by RG 1.174, as follows:

PRA Metric	Frequency
Internal Events LERF	1.12E-06/yr
External Events LERF (Internal events LERF x 1.21)	1.36E-06/yr
Total LERF (Internal + External)	2.48E-06/yr

As detailed above, the results show a significant margin is available to the total LERF threshold of 1E-5/yr. For total LERF to exceed this threshold, an external events multiplier of 7.9 or greater would be required. The associated LERF increase would be 5.7E-7/yr (still in the "small" impact region). Holding all other external event values constant, the Fire PRA CDF could increase to a value of approximately 5.8E-5/yr to remain below the 1E-5/yr total LERF threshold.

These calculations demonstrate that there is significant margin related to external event assessment. The recent Hatch SPRA CDF result from the peer review model is 3.08E-7/yr and the LERF result is 1.02E-7/yr. Both results are significantly lower than the estimated frequencies above and use of the Hatch SPRA results would increase the margin available for external events contribution.

RAI 9

In Section 3.3.2.3, "Plant Changes Not Yet Incorporated into the PRA Model," of Enclosure 1 of the LAR, the licensee stated, in part, that:

A review of the current open items in the database for HNP identified no permanent plant design or operational changes that would significantly impact the results of the risk assessment.

In Table B.2-1, "Resolution of the Hatch PRA Peer Review F&Os Associated with the 10 Not Met SRs [Supporting Requirements]," in Attachment 3 of the August 24, 2016, supplement, Fact and Observation (F&O) MU-C1 identified some deficiencies in the PRA model update process. Please discuss how this review of plant changes not incorporated into the PRA model was performed. Also, please discuss any plant design or operational changes that have not been reflected in the PRA and their impact on the LAR.

SNC Response

SNC provides the following response to RAI 9:

Attachment B in the August 24, 2016 transmittal contained a description of the process for tracking plant changes that might affect the PRA models in sections B.2 and B.2.1. This process was implemented in order to respond to finding 5-8, related to the peer review standard section 1-5.2 item c) requirement to evaluate the cumulative impact of pending changes to the PRA models.
SNC procedures RIE-001 and RIE-014 describe an in-line continuous process where Southern Nuclear Risk Informed Engineering personnel are in the review cycles for plant changes and procedure changes and can evaluate them for impact prior to implementation. The procedures require that each change be evaluated for impact to CDF and LERF individually AND cumulatively. Each change is identified and entered into a model log database, where the impact of the individual change and the cumulative impact of changes not yet incorporated are documented for each entry. Model revisions list what log items have been incorporated so that the log items can be closed.

There are currently 81 open log entries against the Unit 1 internal events level 1 and LERF PRA models. Most of these are correcting minor errors in the CDF logic discovered while developing Fire and Seismic PRA models, or are tracking changes to the plant that have not yet been implemented. The few changes affecting the Level 2 analysis are:

- The use of older pipe failure frequencies for the feedwater and main steam line breaks outside containment. This impacts breaks outside containment with failure to isolate but does not impact the portion of the model used for the ILRT evaluation, although it does reduce the Bin 8 and overall LERF probability by approximately 60%.

- FLEX modifications to the instrument bus electrical systems and pneumatic systems associated with increasing the reliability of the containment hardened vent. This does not affect the portion of the model used for the ILRT evaluation. This reduces the Bin 7 frequency by providing an alternate method of containment heat removal.

- Incorporation of the BWROG revision 3 EPG/SAG guidance into the plant EOPs and SAGs. These change the Bin 2 and Bin 7 sequences by allowing operation of high pressure injection sources for longer periods of time and by allowing containment venting through the hardened vent at lower pressures.

RAI 10

F&Os IFQU-A6-2-7 and IE-A9-1-4 appear to be missing parts of the resolution and resolution status in Tables B.2-1 and B.2-2, "Resolution of the Hatch PRA Peer Review F&Os Associated with the5 [sic] Cat I met only SRs," of Attachment 3 to the LAR, respectively. Please provide the complete information for these F&Os.

SNC Response

SNC provides the following response to RAI 10:

In the corrected risk assessment provided by SNC Letter NL-16-1390, Correction to Attachment 3, submitted to the NRC on August 24, 2016 (ML16238A477), the resolution to IFQU A6-2-7 in table B.2-1 on page B8 refers to the response to IFQU-A5-4-5, which states that after the internal flooding initiators were reduced in number, an additional HRA analysis was performed for the flooding affected actions. The response to IE-A9-1-4 in table B.2-2 begins on page B10 and carries over to page B11.