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Fred Dacimo
Site Vice President
Administration

December 15, 2004

Re: Indian Point Unit 3
Docket No. 50-286
NL-04-156

Document Control Desk
U.S. Nuclear Regulatory Commission
Mail Stop O-P1-17
Washington, DC 20555-0001

Subject: **Reply to RAI Regarding Indian Point 3 Stretch Power Uprate dated November 5, 2004 (TAC MC 3552)**

Reference:

1. Entergy Letter NL-04-069 to NRC; "Proposed Changes to Technical Specifications: Stretch Power Uprate (4.85%) and Adoption of TSTF-339", dated June 3, 2004.
2. NRC letter from Milano to Dacimo Dated 11/5/04 Regarding Stretch Power Uprate, Indian Point Nuclear Generating Unit No. 3 (TAC No. MC3352)

Dear Sir:

Entergy Nuclear Operations, Inc (Entergy) is submitting additional information to support NRC review of the stretch power uprate (SPU) license amendment request (Reference 1) for Indian Point 3 (IP3). This information is being provided as requested by Reference 2.

Attachment 1 is a summary listing of those RAIs that are being addressed in this letter. The responses to the RAIs are provided in Attachment 2, except for responses that contain proprietary information. The proprietary responses and the corresponding non-proprietary version of those responses are provided in Attachments 3 and 4, respectively. Please note that the responses to RAIs SG-1b and SG-2a have been revised from the responses provided in NL-04-145 for RAIs NL-04-073-SG-2 and NL-04-073-SG-3.

As Attachment 3 contains information proprietary to Westinghouse Electric Company, it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information that is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390 of the Commission's regulations. Westinghouse authorization letter dated

A001

December 9, 2004 (CAW-04-1928), with the accompanying affidavit, Proprietary Information Notice, and Copyright Notice is provided in Enclosure A.

Correspondence with respect to the copyright on proprietary aspects of the items listed above or the supporting affidavit should reference CAW-04-1928 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P. O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

In addition, Attachments 5 and 6 contain errata pages for the Stretch Power Uprate Licensing Report transmitted in the original license amendment request, Reference 1. A Table summarizing the changes is provided. Attachment 5 pages are for the proprietary version (WCAP-16212-P) and Attachment 6 pages are for the non-proprietary version (WCAP-16212-NP). Since one page change contains proprietary information, the application for withholding covers that replacement page.

The additional supporting information and errata pages provided in this letter do not alter the conclusions of the no significant hazards evaluation that supports the subject license amendment request. There are no new commitments being made in this submittal. If you have any questions or require additional information, please contact Mr. Kevin Kingsley at (914) 734-6695.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 12/15/2004

Sincerely,

Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachment 1: Summary Listing of RAI Responses Regarding Stretch Power Uprate License Amendment Request for Indian Point 3
Attachment 2: Additional Information for IP3 SPU License Amendment Request, Based on NRC RAIs Issued November 5, 2004.
Attachment 3: Additional Information for IP3 SPU License Amendment Request, Based on NRC RAIs Issued November 5, 2004. (with Proprietary Information)
Attachment 4: Additional Information for IP3 SPU License Amendment Request, Based on NRC RAIs Issued November 5, 2004. (non-Proprietary version of Attachment 3)
Attachment 5: Errata Pages for WCAP-16212-P, Indian Point Nuclear Generating Unit 3 Stretch Power Uprate NSSS And BOP Licensing Report.
Attachment 6: Errata Pages for WCAP-16212-NP, Indian Point Nuclear Generating Unit 3 Stretch Power Uprate NSSS And BOP Licensing Report.
Enclosure A: Westinghouse Authorization Letter Dated December 09, 2004 (CAW-04-1928), with accompanying affidavit, Proprietary Notice, and Copyright Notice
Enclosure B: Engineering Standards Manual IES-3B, Revision 0; "Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3)."

cc: next page

cc: Mr. Patrick D. Milano, Senior Project Manager
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ATTACHMENT 1 TO NL-04-156

SUMMARY LISTING OF RAI RESPONSES PROVIDED IN THIS LETTER

REGARDING STRETCH POWER UPRATE LICENSE AMENDMENT REQUEST

FOR INDIAN POINT 3

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

No.	RAI	IP3 Response	Review Area
1	RSA-1	Att 2 - Non-Proprietary	Reactor Systems and Analyses
2	RSA-2-1	Att 2 - Non-Proprietary	Reactor Systems and Analyses
2	RSA-2-2	Att 3, 4 - Proprietary	Reactor Systems and Analyses
3	RSA-3	Att 3, 4 - Proprietary	Reactor Systems and Analyses
4	RSA-4-1	Att 2 - Non-Proprietary	Reactor Systems and Analyses
4	RSA-4-2	Att 2 - Non-Proprietary	Reactor Systems and Analyses
5	RSA-5	Att 2 - Non-Proprietary	Reactor Systems and Analyses
6	RSA-6	Att 2 - Non-Proprietary	Reactor Systems and Analyses
7	RSA-7-1	Att 3, 4 - Proprietary	Reactor Systems and Analyses
7	RSA-7-2	Att 3, 4 - Proprietary	Reactor Systems and Analyses
8	RSA-8	Att 2 - Non-Proprietary	Reactor Systems and Analyses
9	RSA-9	Att 3, 4 - Proprietary	Reactor Systems and Analyses
10	RSA-10	No Question provided	Reactor Systems and Analyses
11	RSA-11	Att 3, 4 - Proprietary	Reactor Systems and Analyses
12	RSA-12	Att 2 - Non-Proprietary	Reactor Systems and Analyses
13	EL-1a	Att 2 - Non-Proprietary	Electrical
13	EL-1b	Att 2 - Non-Proprietary	Electrical
13	EL-1c	Att 2 - Non-Proprietary	Electrical
13	EL-1d	Att 2 - Non-Proprietary	Electrical
13	EL-1e	Att 2 - Non-Proprietary	Electrical
14	EL-2	Att 2 - Non-Proprietary	Electrical
15	IC-1	Att 2 - Non-Proprietary	Instrumentation and Controls
16	IC-2	Att 2 - Non-Proprietary	Instrumentation and Controls
17	IC-3	Att 2 - Non-Proprietary	Instrumentation and Controls
18	IC-4a	Att 2 - Non-Proprietary	Instrumentation and Controls
18	IC-4b	Att 2 - Non-Proprietary	Instrumentation and Controls
18	IC-4c	Att 2 - Non-Proprietary	Instrumentation and Controls
18	IC-4d	Att 2 - Non-Proprietary	Instrumentation and Controls
18	IC-4e	Att 2 - Non-Proprietary	Instrumentation and Controls
18	IC-4f	Att 2 - Non-Proprietary	Instrumentation and Controls

No.	RAI	IP3 Response	Review Area
19	IC-5	Att 2 - Non-Proprietary	Instrumentation and Controls
20	IC-6	Att 2 - Non-Proprietary	Instrumentation and Controls
21	ME-1	Att 2 - Non-Proprietary	Mechanical Engineering
22	ME-2	Att 2 - Non-Proprietary	Mechanical Engineering
23	ME-3	Att 3, 4 – Proprietary	Mechanical Engineering
24	ME-4	Att 3, 4 – Proprietary	Mechanical Engineering
25	ME-5	Att 3, 4 – Proprietary	Mechanical Engineering
26	ME-6	Att 3, 4 – Proprietary	Mechanical Engineering
27	ME-7	Att 3, 4 – Proprietary	Mechanical Engineering
28	ME-8	Att 2 - Non-Proprietary	Mechanical Engineering
29	ME-9	Att 2 - Non-Proprietary	Mechanical Engineering
30	ME-10	Att 2 - Non-Proprietary	Mechanical Engineering
31	ME-11	Att 3, 4 – Proprietary	Mechanical Engineering
32	ME-12	Att 2 - Non-Proprietary	Mechanical Engineering
33	SI-1a	Att 2 - Non-Proprietary	Reactor Vessel, Pressurizer, and Steam Generator Structural Integrity
33	SI-1b	Att 2 - Non-Proprietary	Reactor Vessel, Pressurizer, and Steam Generator Structural Integrity
34	SI-2	Att 2 - Non-Proprietary	Reactor Vessel, Pressurizer, and Steam Generator Structural Integrity
35	SI-3	Att 2 - Non-Proprietary	Reactor Vessel, Pressurizer, and Steam Generator Structural Integrity
36	PIP-1	Att 2 - Non-Proprietary	Piping
37	PIP-2a	Att 2 - Non-Proprietary	Piping
37	PIP-2b	Att 2 - Non-Proprietary	Piping
37	PIP-2c	Att 2 - Non-Proprietary	Piping
38	FAC-1a	Att 2 - Non-Proprietary	Flow-Accelerated Corrosion Program
38	FAC-1b	Att 2 - Non-Proprietary	Flow-Accelerated Corrosion Program
38	FAC-1c	Att 2 - Non-Proprietary	Flow-Accelerated Corrosion Program
39	FAC-2a	Att 2 - Non-Proprietary	Flow-Accelerated Corrosion Program
39	FAC-2b	Att 2 - Non-Proprietary	Flow-Accelerated Corrosion Program
39	FAC-2c	Att 2 - Non-Proprietary	Flow-Accelerated Corrosion Program

No.	RAI	IP3 Response	Review Area
40	PCP-1a	Att 2 - Non-Proprietary	Protective Coatings Program
40	PCP-1b	Att 2 - Non-Proprietary	Protective Coatings Program
40	PCP-1c	Att 2 - Non-Proprietary	Protective Coatings Program
40	PCP-1d	Att 2 - Non-Proprietary	Protective Coatings Program
40	PCP-1e	Att 2 - Non-Proprietary	Protective Coatings Program
41	SG-1a	NL-04-145 item NL-04-073-SG-2	Steam Generator Structural Integrity Evaluation
41	SG-1b	Att 2 - Non-Proprietary	Steam Generator Structural Integrity Evaluation
41	SG-1c	NL-04-145 item NL-04-073-SG-2	Steam Generator Structural Integrity Evaluation
42	SG-2a	Att 3, 4 – Proprietary	Steam Generator Structural Integrity Evaluation
42	SG-2b	NL-04-145 item NL-04-073-SG-3	Steam Generator Structural Integrity Evaluation

ATTACHMENT 2 TO NL-04-156

ADDITIONAL INFORMATION FOR IP3 SPU LICENSE AMENDMENT REQUEST

BASED ON NRC RAIs ISSUED NOVEMBER 5, 2004

(Refer to Attachments 3 and 4 for other responses involving proprietary information)

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

REACTOR SYSTEMS

Question RSA-1:

In Attachment III (application report) to the June 3, 2004, application, the licensee states the requirements of 10 CFR 50.68(b) apply to IP3 and remain valid for the upgraded fuel design. Explain when the licensing basis changed from 10 CFR 70.24 requirements to 10 CFR 50.68 requirements, and state the specific references by which the change was requested and approved.

Response RSA-1:

By letter dated September 24, 1998 (Reference RSA-1-1), the New York Power Authority (previous owner) requested an exemption from the requirements of 10 CFR 70.24 for IP3. This was pre-10CFR 50.68 and was based on seven criteria provided in Information Notice 97-77 (Reference RSA-1-2). By letter dated December 10, 1998, (Reference RSA-1-3), the NRC granted this exemption. The criteria in 10CFR 50.68 and IN 97-77 are so similar, that compliance with IN 97-77 implies compliance with 10CFR 50.68. However, Section 9.5 of the IP3 FSAR currently states "IP3 is exempt from the requirements of 10 CFR 70.24" and this will be revised in the next update to state that IP3 has chosen to comply with 10CFR50.68(b).

References:

RSA-1-1 IPN-98-101, J. Knubel to USNRC, "10CFR 70.24 Exemption Request", September 24, 1998.

RSA-1-2 NRC Information Notice 97-77, "Exemptions from the Requirements of Section 70.24 of Title 10 of the Code of Federal Regulations," dated October 10, 1997.

RSA-1-3 G. F. Wunder to Mr James Knubel, "Issuance of Exemption", December 10, 1998.

Question RSA-2:

Regarding the charging and volume control system (CVCS) malfunction re-analysis:

Question RSA-2-1:

The licensee assumes complete mixing of the diluted water injected through the cold leg with the active volumes in the RCS. Explain how a dilution front is addressed in the analysis for each plant mode and how a local power spike in the reactor core is precluded.

Response RSA-2-1:

The CVCS malfunction event is discussed in WCAP-16212 Licensing Report Section 6.3.5. The question is best addressed by plant mode and the operation of the Reactor Coolant Pumps and the RHR System.

Modes 1, 2, 3: One or more Reactor Coolant Pumps are in service and thus adequate mixing is assured.

Modes 4 and 5: At least one Reactor Coolant Pump is in service on shutdowns until Reactor Coolant System temperature is less than approximately 170°F. The RHR System is placed in service when the Reactor Coolant System temperature is less than approximately 350°F thus assuring adequate mixing. Similarly, during startup, the RHR System is in service and a Reactor Coolant Pump is placed in service while Reactor Coolant System temperature is less than 200°F. In addition, the Westinghouse Interim Operating Procedure was developed specifically for these modes, addressing the potential effects of a "dilution front" and a limited active mixing volume, and has been incorporated in plant procedures.

In addition, for modes 4 and 5, at the pressures in the Reactor Coolant System associated with RHR operation (less than 450 psig) letdown flow is limited to 120 gpm. Second, only two charging pumps (90 gpm each) are permitted to be available due to low temperature over pressurization restrictions.

Mode 6: At least one RHR pump (providing a minimum flow rate of 1000 gpm) is in service except during short periods. This flow rate is considered adequate for mixing in the lower plenum. The actual flow from one RHR pump would be much higher than 1000 gpm. While the CVCS Malfunction event has been analyzed in the refueling mode, it is administratively precluded. Plant procedures require that the valve in the boron addition/dilution path be placed in manual and closed upon shutting down the last Reactor Coolant Pump. Thus in Mode 6 (Refueling), plant procedures preclude a dilution event.

Based on the above, Entergy concludes that adequate mixing for the active RCS volumes is available or that administrative controls preclude boron dilution.

The time to reach criticality for the CVCS malfunction event, Modes 1, 2 and 6, is calculated based on the following equation.

Cb(t) = Cbi * e ^ [-(mdil / M) * t]

Where:
Cb(t) = boron concentration of the system as a function of time
Cbi = initial boron concentration of the system
mdil = mass flow rate of diluent
M = initial mass of the system
t = time

In using this equation, it is assumed that the system has a constant mass and that the concentration of the diluent is equal to zero.

Question RSA-2-2:

The IP3 Final Safety Analysis Report states the reactor coolant system (RCS) volume assumed in the analysis was 8,630 ft^3 for Modes 1 and 2. However, the volume in the application report is 9,350 ft^3 for Modes 1 and 2. Provide the justification for the change in RCS volume used in the analyses. Was the methodology used for the SPU analysis consistent with the analysis of record?

Response RSA-2-2:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question RSA-3:

The licensee states generic transient statepoints designed to bound IP3 at SPU conditions were used in the rod control cluster assembly (RCCA) Drop/Misoperation re analysis. State the document which references these statepoints and demonstrate they are applicable to IP3.

Response RSA-3:

The response to this question was provided in letter NL-04-145 of November 18, 2004, in Attachment 2 in response to IP2 item Question NL-04-073-RSA-10b.

Question RSA-4:

Regarding the loss-of-normal feedwater (LONF) transient analysis:

Question RSA-4-1:

Currently, the turbine-driven auxiliary feedwater pump (TDAFWP) is not credited to mitigate this transient. In its SPU submittal, the licensee states the TDAFWP is valved out during normal operation. Therefore, although the TDAFWP is automatically actuated, this pump is not available to deliver flow to the steam generator until operator action is taken to align the TDAFWP. Provide a detailed description of the steps the operator takes to complete this action, and justify the operators are capable of performing this action in 10 minutes.

Response RSA-4-1:

The response to this question was provided in letter NL-04-145 of November 18, 2004, in Attachment 2 in response to IP2 item Question NL-04-073-RSA-12a.

Question RSA-4-2:

The analysis of record states the motor-driven auxiliary feedwater pumps are assumed to supply flow within 70 seconds of initiating signal. Explain why the new time of 60 seconds is stated in the application report, and show this is a conservative assumption.

Response RSA-4-2:

For a Westinghouse-designed plant, 60 seconds is a typical value for this delay, which includes sensor and logic delays, diesel generating starting and loading delays, as well as the time to get the AFW pumps up to speed. Previous to 1998, the value assumed for this delay in the IP3 analysis of record was also 60 seconds. However, when surveillance tests around that time indicated that the assumed delay time may be exceeded, it was decided to increase the delay time assumed in the IP3 LONF analysis from 60 seconds to 70 seconds, as reflected in the current analysis of record. Since it has been shown in more recent surveillance tests that a value of 60 seconds will not be exceeded for this delay, the delay time was changed from 70 seconds back to 60 seconds as part of the SPU. Also, this assumption is considered conservative because surveillance tests are in place to ensure that the assumed value bounds the measured plant value.

Question RSA-5:

In Section 7.4 of the application report, the licensee states rod internal pressure and clad fatigue criteria were met for the SPU condition. Provide the technical justification explaining how maintaining a vessel temperature of 572°F will meet the rod internal pressure and clad fatigue criteria for the SPU operation. Also, provide the analytical basis that shows the clad fatigue criterion is met under SPU core conditions with a vessel average temperature of 572°F.

Response RSA-5:

The vessel average temperature is one of the plant assumptions used in determining acceptable fuel performance. The following fuel performance parameters are adversely affected as vessel average temperature is increased: clad corrosion, clad creep, fission gas release, clad stress, clad strain and clad fatigue. In particular, rod internal pressure and clad fatigue analyses have been performed to establish a maximum vessel average temperature in which acceptable design margin would be available in conjunction with SPU operation. Cycle-specific core designs and fuel performance analyses are also performed for each reload cycle. Vessel average temperature is one of the specific operating conditions assumed in the determination that all fuel rod design criteria are met.

The Westinghouse analytic approach is based on the Langer-O'Donnell strain fatigue model conservatively bounded by Westinghouse testing results. The clad fatigue limit assumes conservative load follow scenarios over the life of the fuel rod to model the accumulated effect of short-term cyclic, cladding stress and strain as well as normal plant shutdowns and returns to full power. The incremental fatigue usage is calculated based on the stress amplitude and number of cycles to failure. The clad average temperature is used to determine the number of cycles to failure, therefore power level and vessel average temperature increases will tend to increase clad fatigue levels. Analysis of representative rod power histories at the SPU conditions still resulted in acceptable clad fatigue levels. The clad fatigue criterion is met under SPU core conditions with a maximum vessel average temperature of 572.0°F by appropriate cycle-specific core design.

Question RSA-6:

The licensee used the LOFTTR2 computer code in its SPU steam generator tube rupture re-analysis. Demonstrate that the code is applicable for use at IP3 and that all conditions and limitations are met.

Response RSA-6:

The current licensing basis for IP3 for SGTR uses a simple mass and energy (M&E) balance in the calculation of the break flow and steam releases. This method was also used for the SPU calculations to define inputs for the dose analyses. In order to show that the mass and energy balance method provides conservative inputs for dose analyses, a better estimate LOFTTR2 calculation was performed to show that terminating break flow at 60 minutes would result in doses that are bounded by the doses calculated by the mass and energy balance method. A better estimate LOFFTR2 calculation was also performed to demonstrate margin to steam generator overfill. The SPU licensing basis calculation continues to be based on the mass and energy balance method.

The LOFTTR2 calculation used the Westinghouse configuration control version of the code with inputs chosen to properly model the IP3 plant and its operation. The IP3 SPU better estimate SGTR calculations were performed using the analysis methodology developed in WCAP-10698 and Supplement 1 to WCAP-10698 for use with the LOFTTR2 program. The methodology was developed by the SGTR Subgroup of the WOG and was approved by the Nuclear Regulatory Commission (NRC) in Safety Evaluation Reports (SERs) dated December 17, 1985 and March 30, 1987.

Question RSA-7:

Regarding the complete loss-of-reactor-coolant flow transient analysis:

Question RSA-7-1:

The licensee assumed an undervoltage trip time delay of 1.5 seconds. Explain the reason for the time delay and why this is a conservative assumption in the analysis.

Response RSA-7-1:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question RSA-7-2:

The licensee assumed rod motion occurs at 1.6 seconds, following a 0.6 second under frequency trip time delay. Explain the reason for the time delay and why this is a conservative assumption in the analysis.

Response RSA-7-2:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question RSA-8:

Many cycle-specific parameters have been relocated to the core operating limits report (COLR), which was not submitted with the application. These include the Reactor Core Safety Limit (RCSL) figure, the values of the constants in the Over-temperature and Over-power ΔT functions, respectively (Notes 1 and 2 in Table 3.3.1 1), and the limit values of the pressurizer pressure, RCS average temperature, and RCS total flow rate (limiting condition for operation (LCO) 3.4.1).

Provide the RCSL figure and the values of the constants of the OTΔT and OPΔT functions, and the RCS flow, average temperature and pressure limit values in the COLR, or confirm that they are the same as those provided in the application report.

Response RSA-8:

A response to this question (except for the RCSL figure) was provided in letter NL-04-145 of November 18, 2004, in Attachment 2 in response to IP2 item NL-04-073-RSA-20. That response is provided below. The RCSL figure is provided as Figure 6.3-1 of WCAP-16212-P and WCAP-16212-NP and here as Figure RSA-8-1.

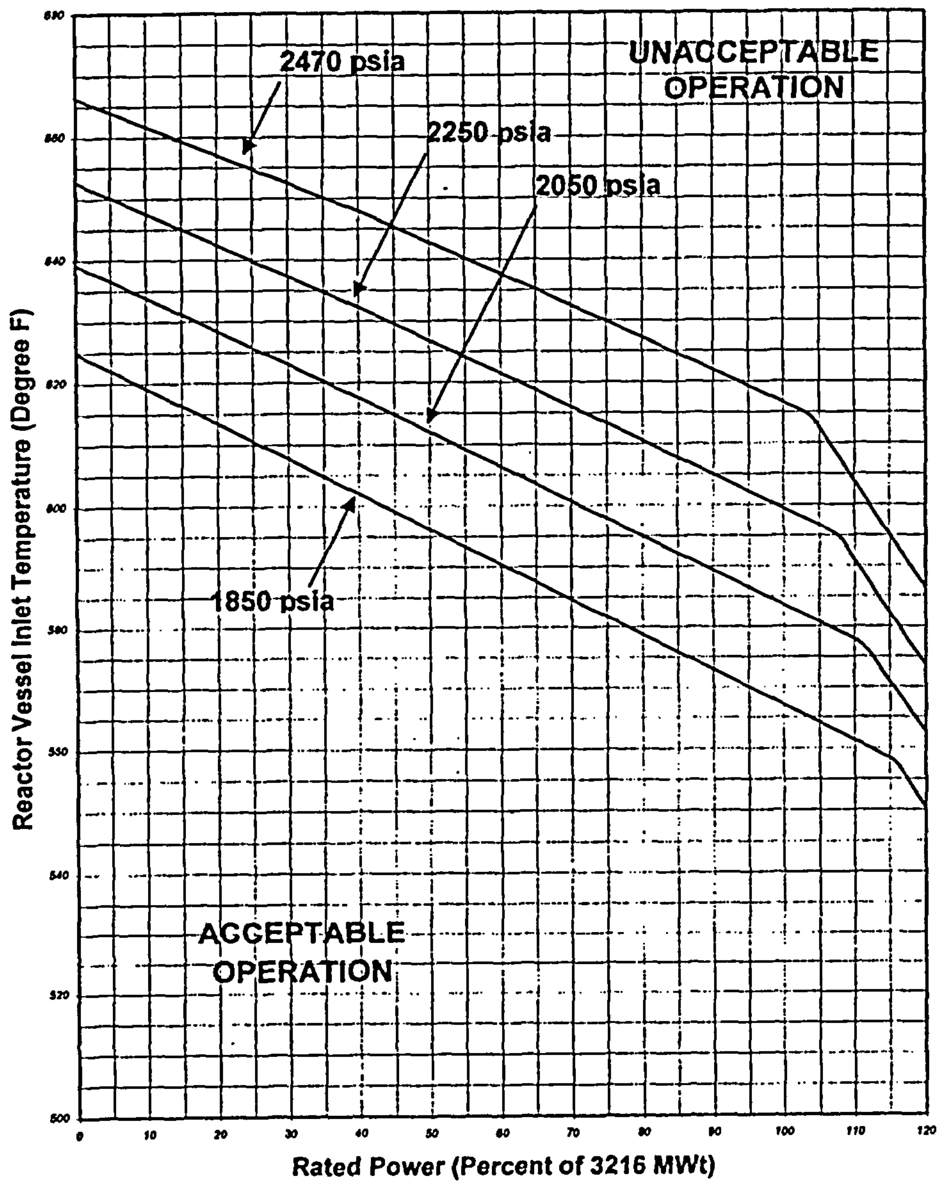
Question NL-04-073-RSA-20:
Many cycle-specific parameters have been relocated to the core operating limits report (COLR), which was not submitted with the SPU application. These include the values of the constants in the over-temperature and over-power ΔT functions, respectively (Notes 1 and 2 in Table 3.3.1- 1), and the DNBR limiting values of the pressurizer pressure, RCS average temperature, and RCS total flow rate (LCO 3.4.1). Provide either the COLR or the values of these parameters.

Response NL-04-073-RSA-20:

The IP3 Licensing Report (Attachment III of NL-04-069) provides the values for DNB-related constants and limiting values in Section 6.3.1 on pages 6.3-3 through 6.3-6. Additional information regarding the limiting Safety Analysis Limits (SALs) and Nominal Trip Setpoints (NTSs) is provided in Table 6.10-1 of WCAP-16212-P and WCAP-16212-NP for those items that changed as a result of the SPU. Items not listed in Table 6.10-1 were not changed by the SPU. Additional comparative information is also provided in the response to I&C item NL-04-073-IC-4 Table NL-04-073-IC-4-1 which provides comparison of before and after values for the RPS and ESFAS parameters that changed as a result of the SPU. The cycle-specific values for the COLR are not yet available (the reload design process will complete the revised COLR in February 2005), but will be bounded by the SAL and NTS values provided in Table 6.10-1 of WCAP-16212-P and WCAP-16212-NP. The preliminary COLR values for pressurizer pressure, RCS average temperature, and RCS total flow rate are pressurizer pressure of ≥ 2204 psia, RCS average T_{avg} temperature of ≤ 576.7°F for a full power T_{avg} of 572°F, and RCS total flow rate of ≥364,700 gpm.

Figure RSA-8-1 RCSL Figure from Draft IP3 Cycle 14 COLR

REACTOR CORE SAFETY LIMIT – FOUR LOOPS IN OPERATION



Question RSA-9:

Section 6.3.1 of the application report describes the revised instrumentation ranges for RCS temperature measurement chosen for IP3 after implementation of the SPU to ensure proper operation of the OTΔT and OPΔT reactor trip functions over a realistic full power operating T_{avg} range of 562.0°F to 572.0°F as follows:

520°F $\leq T_{cold} \leq$ 640°F
540°F $\leq T_{avg} \leq$ 615°F
520°F $\leq T_{hot} \leq$ 640°F

These revised instrumentation ranges are said to be derived from the instrumentation ranges for proper operation of the OTΔT and OPΔT functions over the entire range (T_{avg} from 549.0°F to 572.0°F) and a reduced, more realistic range (T_{avg} from 562.0°F to 572.0°F), respectively, of applicable full power operating RCS temperatures. Please provide a more detailed explanation of how these revised instrumentation ranges are derived.

Response RSA-9:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question RSA-10:

No question listed

Response RSA-10:

No response is required.

Question RSA-11:

Footnote 7 of Table 2.1-2 in the application report indicates that the RCS minimum measured flow of 364,700 gpm includes a 2.9% flow measurement uncertainty. Attachment I to the June 3 application regarding the proposed TS changes states that the SPU flow measurement uncertainty was calculated using the existing methodology described in WCAP-11397-P-A, and remains at the current value of 2.9%. Since WCAP-11397-P-A simply uses, rather than calculates, the RCS flow measurement uncertainty value, provide the calculation that shows the 2.9% RCS flow measurement uncertainty is applicable for use at IP3 under SPU conditions.

Response RSA-11:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question RSA-12:

In Section 4.1.4 on the safety injection system/containment spray system of application report, the licensee states the high-head safety injection (HHSI) system was modified by permanently closing two cold leg branch lines, and throttling the HHSI system to provide higher cold leg and hot leg flows. What is the design function of the branch line? Why is it acceptable to defeat this function permanently? Provide a system diagram which depicts the branch lines that were closed. Discuss how this is administratively controlled and how the redundancy and independence of the system was preserved.

Response RSA-12:

A specific response is provided each question provided in RSA-12 as follows.

Question: What is the design function of the branch line?

The branch line piping connects the two HHSI pump discharge headers (typically called the 33/BIT and 31/non-BIT headers) to each of the respective reactor coolant loop cold legs and hot legs (i.e., there is no direct reactor vessel injection with this system design). For ease of discussion, a simplified diagram of the Indian Point Unit 3 HHSI system is provided in Figure RSA-12-1, while the attached Indian Point 3 UFSAR Figures 6.2-1A and 6.2-1B show the actual plant system diagram.

Question: Why is it acceptable to defeat this function permanently?

Revised HHSI system performance (both hot leg and cold leg performance) was calculated with the 856A and 856F manual valves permanently closed. This HHSI flow performance data was then used in the various accident analyses performed in support of the Indian Point 3 SPU program. The appropriate limiting single failures and spilling line (e.g., flow from branch line(s) connected to a broken loop may not be credited as safety injection flow to the reactor coolant system) assumptions were also applied in calculating the HHSI system flow performance data. The driving reason for permanently closing the 856A and 856F lines is to achieve higher hot leg recirculation flow performance, required to support the SPU program, while maintaining the maximum allowable HHSI pump flow limits.

Question: Provide a system diagram which depicts the branch lines that were closed.

Figures 6.2-1A and 6.2-1B are system diagrams provided in the Indian Point 3 UFSAR. A simplified figure of the system, showing the lines that are closed, is provided as Figure RSA-12-1 attached.

Question: Discuss how this is administratively controlled and how the redundancy and independence of the system was preserved

The 'permanently' closed valves will be administratively controlled by changing the normal position to locked closed. The valves can be re-opened and subsequently re-closed, as required, during plant shutdown to perform various surveillances on the remainder of the line(s)/components that will remain intact, and connected to the RCS pressure boundary.

As discussed above, revised HHSI system performance (both hot leg and cold leg performance) was calculated with the 856A and 856F manual valves permanently closed. This HHSI flow performance data was then used in the various accident analyses performed in support of the Indian Point 3 SPU program. The appropriate limiting single failures and spilling line assumptions were also applied in calculating the HHSI system flow performance data, including spurious closure of a single cold leg 856 valve as a single active failure. The closure of 856A and 856F valves did not affect the failure analysis described on UFSAR Table 6.2-7, except for the UFSAR page markup shown below.

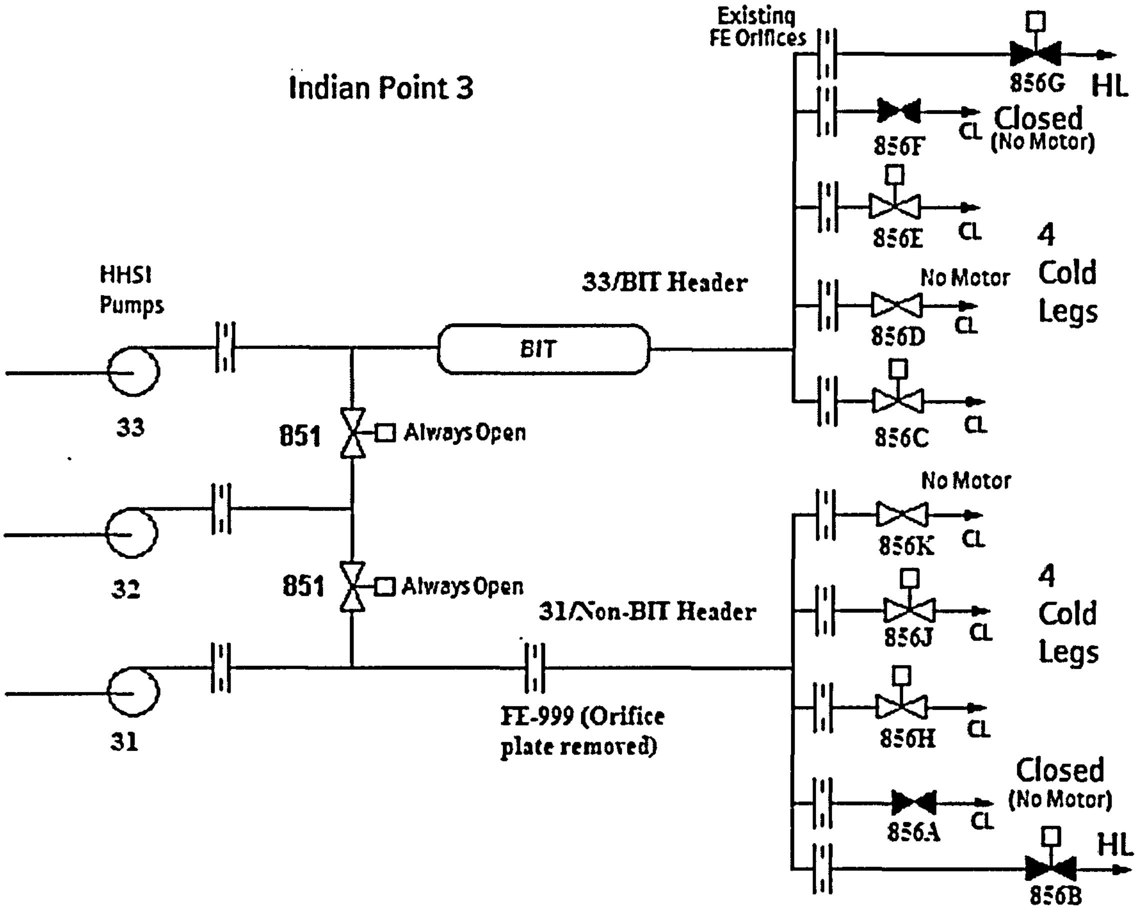
IP3
FSAR UPDATE

TABLE 6.2-7
(Sheet 4 of 7)

SINGLE ACTIVE FAILURE ANALYSIS – SAFETY INJECTION SYSTEM

Component	Malfunction	Comments
6) High-head safety injection header cold leg isolation valves (856C, 856E, 856H, 856J)	Fails closed	Valves are normally open during power operation with AC power supplied. The reduced flow capability with single valve closure is ~~offset~~ analyzed with ~~by~~ the flow delivery of all three safety injection pumps
E. Emergency Power: (injection or recirculation phase)		
1) Emergency Diesel 31	Fails to run	Two of three safety injection pumps, one of two residual heat removal pumps and two of two recirculation pumps available to operate
2) Emergency Diesel 32	Fails to run	Two of three safety injection pumps, one of two residual heat removal pumps and one of two recirculation pumps available to operate
3) Emergency Diesel 33	Fails to run	Two of three safety injection pumps, two of two residual heat removal pumps and one of two recirculation pumps available to operate
F. Valves Operated from Control Room for Recirculation (recirculation phase)		
1) Recirculation internal recirculation isolation (valves 1802A & 1802B)	Fails to open	Two valves in parallel, one valve in either line is required to open

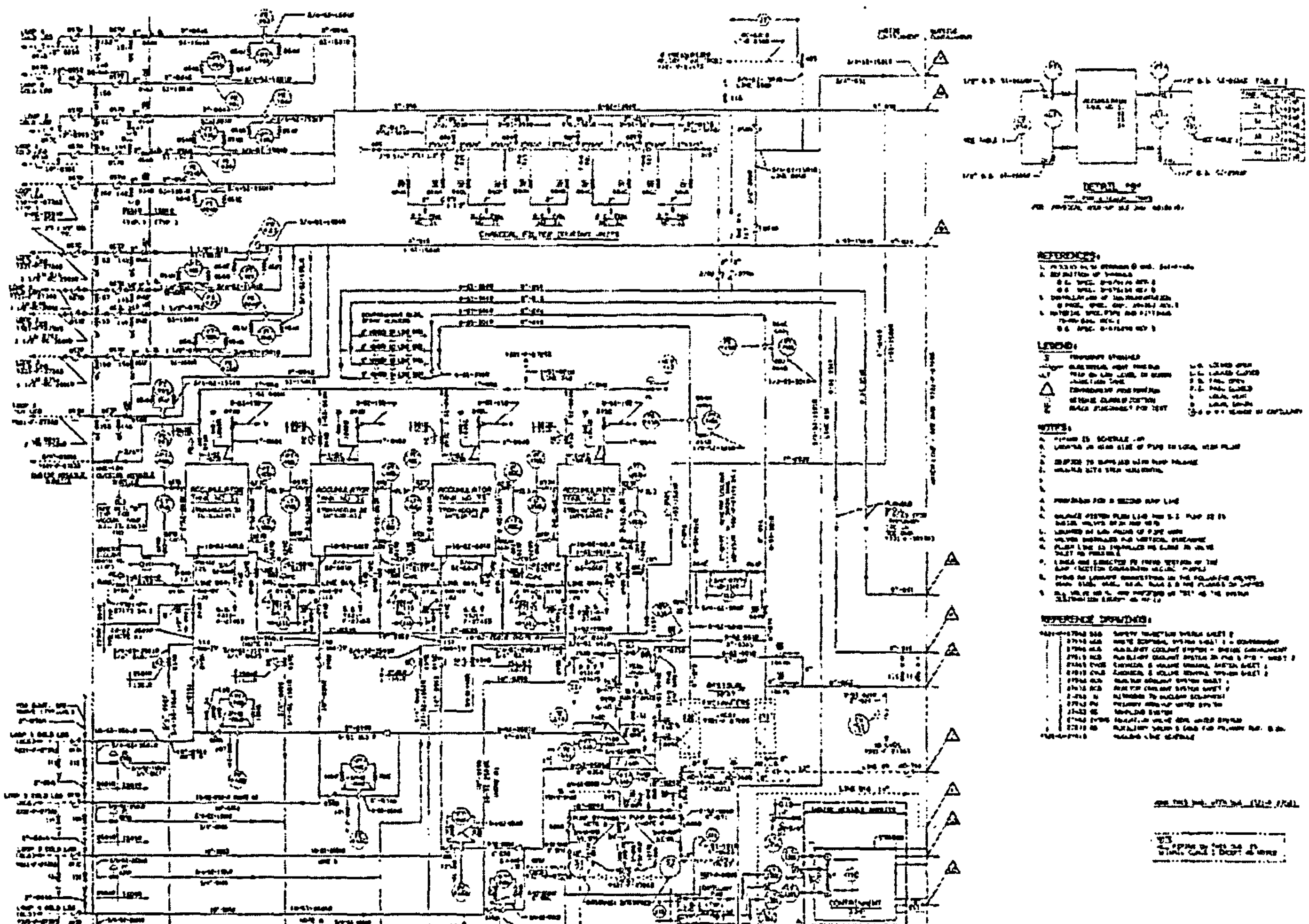
Figure 1



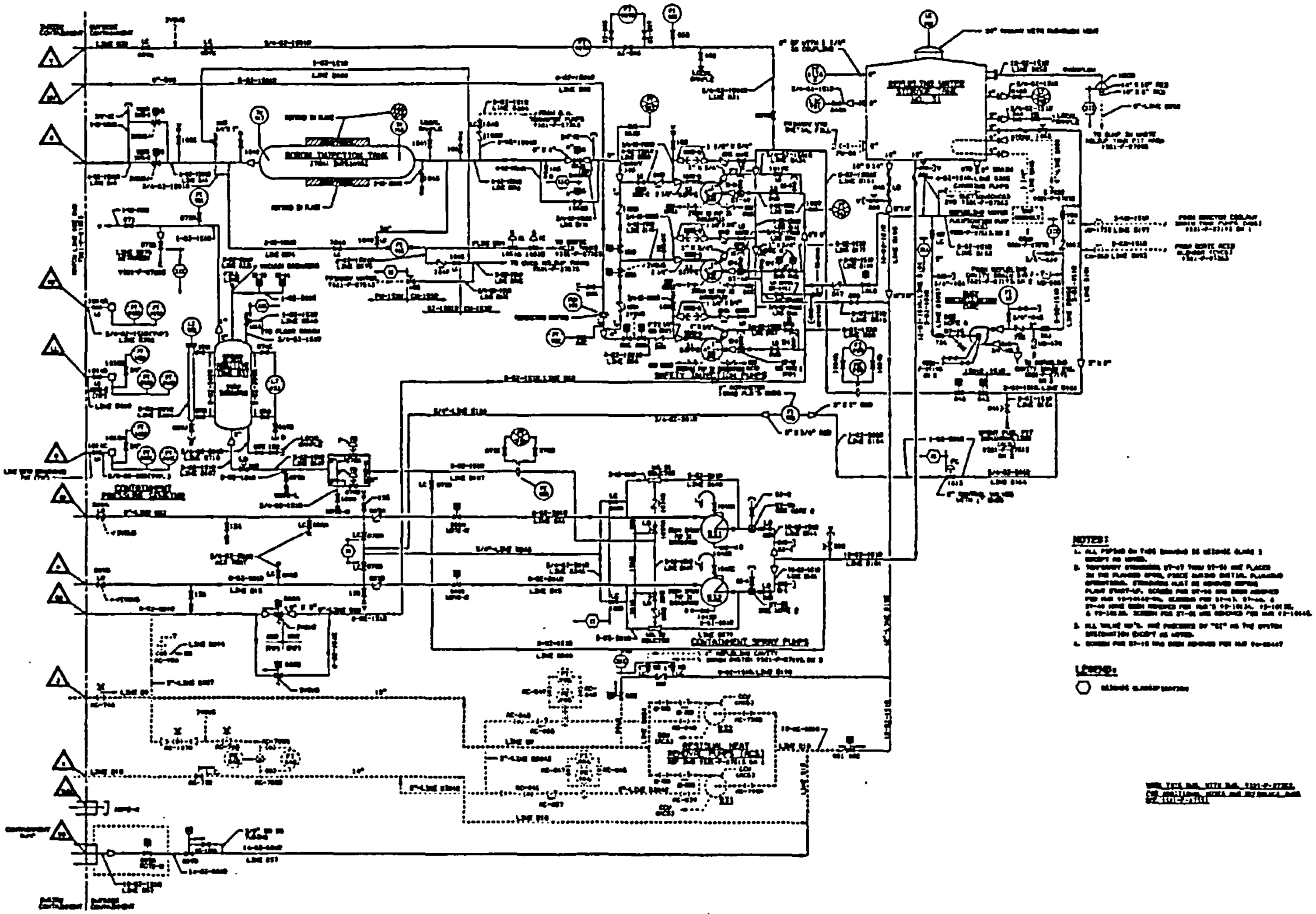
Summary Table of 856 Valves

Valve Number	Valve Operator	HHSI Header	To RCS Loop	Remarks
856A	Manual	31/non-BIT	CL 1	Valve permanently closed
856B	MOV	31/non-BIT	HL 3	
856C	MOV	33/BIT	CL 4	
856D	Manual	33/BIT	CL 2	
856E	MOV	33/BIT	CL 1	
856F	Manual	33/BIT	CL 3	Valve permanently closed
856G	MOV	33/BIT	HL 1	
856H	MOV	31/non-BIT	CL 3	
856J	MOV	31/non-BIT	CL 2	
856K	Manual	31/non-BIT	CL 4	

MOV = Motor Operated Valve
CL = RCS Cold Leg
HL = RCS Hot Leg
BIT = Boron Injection Tank.



INDIAN POINT 3 FSAR UPDATE
FLOW DIAGRAM
SAFETY INJECTION SYSTEM
SHEET NO. 1
REV. 1 JUN 2000 | FIG NO. 6.2-1A



INDIAN POINT 3 FSAR UPDATE

FLOW DIAGRAM
SAFETY INJECTION SYSTEM
SHEET NO. 2

REV. 9 JUN 2000 | FIG. NO. 6.2-1B

F-27505, REV 38

ELECTRICAL

Question EL-1:

Address and discuss the following points:

Question EL-1a:

Identify the nature and quantity of megavolt-amperes reactive (MVAR) support necessary to maintain post-trip loads and minimum voltage levels.

Response EL-1a:

Indian Point 3 is not required to maintain any specific MVAR loading during normal operation.

Question EL-1b:

Identify the MVAR contributions that IP3 is credited for providing to the offsite power system or grid.

Response EL-1b:

Indian Point 3 was evaluated by the NYISO for the previous 1.4% uprating at 225 MVAR Lagging and 170 MVAR Leading.

Question EL-1c:

After the power uprate, identify any changes in MVAR quantities associated with Items a. and b. above.

Response EL-1c:

After the uprate there is no change in a, and the new values for b. are 225 MVAR Lagging and 100 MVAR leading. The decrease in leading reactive support was determined to have little or no impact on system voltage control. Therefore, for IP3 no remediation was required to mitigate the reduction in leading reactive capability.

Question EL-1d:

Discuss any compensatory measures to adjust for any shortfalls in Item c. above.

Response EL-1d:

The NYISO approved the SRIS evaluation of the uprating (225 MVAR Lagging and 100 MVAR Leading) without requiring any compensatory measures.

Indian Point 3 is connected to the Con Edison electrical transmission system that is operated under the rules of the New York Independent System Operator (NYISO). The NYISO and the interconnecting transmission owner have reviewed and approved the MVAR capability of IP3 at SPU conditions. Once the maximum MVAR capability of the units connected to the system has been reached, the NYISO has the authority to order a reduction in generator MWe output to achieve the needed MVAR support. Indian Point 3 is obligated to respond to such a request.

Any need for additional MVAR support on a grid-wide basis would be identified and addressed by the NYISO as part of their annual system reliability studies.

All large generators within the NYISO control area are required to perform an annual reactive capability test. The results of the test determine the annual reactive compensation payment to the generator. Historically the MVAR values achieved by IP3 during this testing have been lower than the unit's design capability because the generator exciter voltage, and/or grid voltage limits are reached prior to any generator capability limits. At the uprate MWe output, Indian Point 3's reactive capabilities are still within the generator and main transformers capability/rating. NYISO approval of the IP3 SPU (at 225 MVAR lagging and 100 MVAR leading) did not require any compensatory measures.

Question EL-1e:

Evaluate the impact of any MVAR shortfall listed in Item d. above on the ability of the offsite power system to maintain minimum post-trip voltage levels and to supply power to safety buses during peak electrical demand periods. The subject evaluation should document any information exchanges with the transmission system operator.

Response EL-1e:

There is no MVAR "shortfall" listed in response to item d. The evaluation performed by and for the NYISO was an extensive System Reliability Impact Study in accordance with the NYISO rules. This study is discussed in the License Amendment Request in Section 9.8.1.9.1.

Question EL-2:

The licensee stated that for Phase 1 of the stretch power uprate (1080 MWe), the isophase bus (IPB) bus duct is capable of operating within its ratings. In Phase 2, the main generator's output will increase to 1093.5 MWe. Increasing the generator output to 1093.5 MWe, and operating the generator within the proposed reactive power limits, causes the IPB duct to operate slightly outside its rating. The load is only exceeded during extreme system grid conditions and can be permanently addressed with future Phase 2 modifications to the IPB. Describe in detail the Phase 2 modifications to the IPB duct.

Response EL-2:

As indicated in the LAR submittal for IP3 the Phase 1 power level of 1080 MWe is not expected to require any modifications to the Iso-phase bus duct cooling system. At the Phase 2 power level the generator output is calculated to reach a maximum 1093.5 MWe (including a 0.5% margin in the heat balance). The Phase 2 power level may require similar modifications as was done for the IP2 Iso-phase bus duct cooling system. The extent of this modification could include (worst case) the following:

- New higher capacity cooling coils,
- New higher capacity fans with associated dampers and
- Removal of the first filter rack to reduce pressure loss and to increase air flow.

In addition to the above hardware improvements, additional maintenance is planed to improve the reliability of the electrical ducting.

INSTRUMENTATION AND CONTROLS

Question IC-1:

During the September 14, 2004, meeting between the licensee and the NRC staffs, the licensee stated that the IP3 RPS and ESFAS TSs allowable values (AVs) were calculated based on Instrument Society of America (ISA) Standard 67.04, part II, Method 3. However, in Attachment I, Section 2, "Proposed Changes," the application stated "a calculation method using ISA-RP67.04 Method 2."

Clarify which method was used for each of the protective functions in the IP3 SPU application. Discuss the differences from methodology used for IP2.

Response IC-1:

During the September 14th meeting between Entergy and NRC staff, Entergy stated that all Allowable Values (AV) for RPS and ESFAS functions prior to the changed values in the SPU amendment request were determined using Method 3 of the ISA Standard 67.04. Entergy also stated that, as highlighted in the SPU amendment request, for the RPS and ESFAS functions whose setpoints were being changed for SPU operation, the Allowable Values proposed for the SPU conservatively bound AVs calculated by both Method 3 and Method 2 of the ISA guide, Method 2 being limiting in all cases.

The AV method used for IP2 first computes a base AV using a conservative version of the ISA Method 3 guideline. It is conservative in that it does not allow consideration of all the sensed uncertainty allowances recognized by the ISA as being present during a surveillance test. After this base AV is determined, a "check" recalculation is performed using the remaining "unsensed" allowances (as described in the ISA guide for a Method 2 calculation.) The more conservative value of the "base" AV or the "check" AV is adopted as the proposed license value. The adopted Method 2 value is also more conservative than required by the ISA guide, in similar fashion to the Method 3 computation, because of the incorporation of normal Temperature Effects as unsensed allowances.

The AV method used for the IP3 SPU license amendment basically is the same as used for IP2 with the minor extra conservatism of having M&TE and Power Supply Effect allowances allocated to the unsensed Method 2 computations as opposed to the sensed Method 3 computations.

Question IC-2:

Explain how the component test procedure acceptance criteria are determined and show that they do indeed provide adequate assurance that the channel AVs are suitably protected. Explain how this approach is compatible with the requirements of 10 CFR 50.36, which requires that the limiting safety system settings be specified in the TSs. Since channel performance is not assessed against the TS AVs unless some other criterion indicates that closer examination is warranted, those other criteria, which are not controlled by the TSs, can result in the TS criteria not being applied. Discuss the differences in methodology used for IP2 and 3.

Response IC-2:

Answered previously in response to RAI NL-04-073 IC-2 in letter NL-04-145. The IP2 and IP3 methodologies are the same.

Question IC-3:

Explain the difference in trip functions listed on Table 6.10-1, "SPU Summary of RTS/ESFAS Setpoint Calculations," for those in the IP2 SPU. IP2 has trip functions setpoint changes for "RCS flow low reactor trip," "SG [steam generator] level low-low reactor trip," "SG level high-feedwater isolation," and "Steamline pressure low SI/SL actuation." These changes were not listed on Table 6.10-1 of IP3. On the other hand, IP3 has trip functions setpoint changes for "Pressurizer pressure low reactor trip", and "Pressurizer pressure low SI initiation." These changes were not listed on Table 6.10-1 of IP2.

Response IC-3:

For the IP2 low RCS flow function, the nominal trip setpoint (NTS) and safety analysis limit (SAL) values remained the same and it was only the Tech Spec allowable value (AV) that changed from pre-SPU. As a result of the calculations associated with IP2 RTD replacement program, which was performed concurrent with the SPU program, there were small changes in the IP2 RCS flow calorimetric uncertainty. Since the RCS flow calorimetric uncertainty is an input to the low RCS flow function, the Tech Spec AV for this function also changed slightly. This change was not required for IP3 because there was no RTD replacement program for IP3.

Due to the resolution of generic steam generator water level uncertainty issues (NSAL-02-03, NSAL-02-04, NSAL-02-05 and NSAL-03-09), which were not directly related to the SPU, there were changes in the IP2 high-high steam generator water level SAL and Tech Spec AV and low-low steam generator water level Tech Spec AV from pre-SPU. These changes were not required for IP3 because sufficient margins existed for IP3 to accommodate any changes resulting from the resolution of the generic water level uncertainty issues.

For the IP2 low steamline pressure function, the NTS, SAL and Tech Spec AV were all changed from pre-SPU. Preliminary transient calculations for the IP2 HZP SLB – Core Response analysis showed that with the pre-SPU SAL for this function, there was unacceptable timing of the coincidence logic on high steam flow / low steamline pressure. This occurred due to past setpoint changes (from original plant settings) that were simply made to increase plant setpoint margin. To address this timing issue, the SAL value (and associated NTS and Tech Spec AV) was increased, such that the coincidence logic would occur sooner in the HZP SLB transient. This change was not required for IP3 because the pre-SPU SAL was already sufficiently high enough for the appropriate coincidence logic to occur.

For the IP3 low pressurizer pressure reactor trip function, the NTS, SAL and Tech Spec AV were all changed from pre-SPU. This change to the SAL (and subsequently the NTS and Tech Spec AV) was made in order to generate OTΔT and OPΔT reactor trip SALs that were as similar as possible between IP2 and IP3 for the SPU. The specific reason that the SAL for the low pressurizer pressure reactor trip function had to be changed was that the OTΔT and OPΔT reactor trip functions are required to protect the core between the low and high pressurizer pressure reactor trips. As such, the low pressurizer pressure reactor trip SAL directly affects the OTΔT and OPΔT SALs required to protect the core, and had to be changed for IP3 to a value similar to that used for IP2. This change was not required for IP2 because the change to IP3 was made in order to make it similar to IP2.

For the IP3 low pressurizer pressure SI function, the NTS and Tech Spec AV were changed from pre-SPU. These changes to the NTS and Technical Specification AV were made to more closely align the IP3 values with those of IP2 and also to provide more traditional bottom of scale margin for the setpoint. These changes still accommodate the existing SAL value. This change was not required for IP2 because no SAL change was required for SPU.

Question IC-4:

Provide the setpoint calculation documents for the following IP3 protection system trip functions listed in Table 6.10-1:

Nuclear instrumentation system (NIS) power range reactor trip high setpoint function

Overtemperature ΔT reactor trip and Overpower ΔT reactor trip functions

Pressurizer pressure low reactor trip function

Pressurizer pressure low safety injection initiation

Steam flow in two steamlines-high (SI/SL actuation)

Tavg -low coincidence with high steam flow (SI/SL actuation)

Response IC-4:

Calculations were previously provided in response to RAI NL-04-073 IC-4 in letter NL-04-145.

Question IC-5:

Provide a copy of "IP3 Engineering Standard IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology, Rev. 0," listed as Reference 2 in Section 6.10.5.

Response IC-5:

As requested, we are providing a copy of IP3 Engineering Standard IES-3B Rev. 0. See Enclosure B of this letter. It should be noted that this standard only describes the use of ISA Method 3 for the determination of Allowable Values. A description of the Method 2 process adopted for the IP3 SPU changed RPS and ESFAS functions is included in the response to IC-1.

Question IC-6:

Provide a statement to clarify that no modification to the existing instrumentation and controls are required for the stretch power uprate except for certain RPS/ESFAS nominal trip setpoint and TSs allowable value changes and that the IP3 instrumentation and control systems will continue to perform their intended functions as required by plant license.

Response IC-6:

Answered previously in response to NL-04-073-IC-7 in letter NL-04-145.

MECHANICAL ENGINEERING

Question ME-1:

Section 3.1.3 of the application report states that the IP3 Model 44F SG design includes a primary-to-secondary pressure differential design limit of 1550 psid and this limit has been set to 1700 psid to minimize plant impact. This limit has also been used at IP2. Confirm how the set limit of the primary-to-secondary pressure differential is acceptable to be higher than the design basis.

Response ME-1:

As described in Section 3.1.3 of WCAP-16212-P, the maximum allowable steam generator primary-to-secondary pressure differential is increased from the existing 1550 psi value to 1700 psi for normal operating conditions. The structural evaluation of the primary-to-secondary pressure differential limit of 1700 psi is discussed in Section 5.6.3, Evaluation of Primary-to-Secondary Side Pressure Differential. Section 5.6.3 notes that the SG design specification has been revised to a design pressure limit for primary-to-secondary pressure differential of 1700 psi for normal operating conditions. The results show that the maximum primary-to-secondary pressure gradients are less than the allowable values for normal operating conditions (1700 psi) and upset operating conditions (1700 psi x 1.1 = 1870 psi). The SG has been found structurally acceptable for the increased primary-to-secondary pressure differential based on the ASME Code requirements.

Question ME-2:

In Table 3.1-1, the values of T_{steam} and P_{steam} at Low T_{avg} and T_{feed} for the present design do not match the values of Table 2.1-1 and Table 2.1-2. Explain why these values are different.

Response ME-2:

As described on footnote 3 of Table 3.1-1, the minimum full power steam pressure has been set to 650 psia to ensure that this primary-to-secondary pressure differential limit of 1700 psid is not violated. The steam temperature is set at the saturation temperature for 650 psia. This SG pressure and temperature are used as the starting point for the low-T_{avg} design transients.

The value of 427.4°F in Table 2.1-1 for current conditions is a typo. The value should be 427.8°F. The value in Table 3.1-1 for feedwater temperature (427.8°F) is correct.

Question ME-3:

In Table 5.1-1, the numerical value of the stress intensity for the CRDM Housings is less than the allowable American Society of Mechanical Engineers, Boiler and Pressure Vessel Code (ASME Code), Section III value of $3S_m$. However, the equation is written to indicate that the $3S_m$ value is exceeded. This error appears to be editorial. Confirm whether our observation is valid.

Response ME-3:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question ME-4:

In Table 5.1-1, the stress intensity of the reactor vessel closure studs is very close to the allowable ASME Code allowable limit. Provide a summary of the calculation of the stress intensity and the cumulative usage factors (CUFs) for the closure studs.

Response ME-4:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question ME-5:

Page 5.2-13 of the application states that the reactor pressure vessel internals were designed to meet the intent of Subsection NG of the ASME Code, Section III. It also states that a plant-specific stress report on the reactor pressure vessel internals was not required, and that the structural integrity of the internals has been ensured by analyses performed on both generic and plant-specific bases. Provide the calculated stresses at the uprated power level for components listed in Table 5.2-1 in comparison to the ASME Code allowed stress limits.

Response ME-5:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question ME-6:

In Section 5.2.4.2, "Flow Induced Vibration (FIV)," the licensee indicated that, based on the analysis for the IP3 reactor internals, the response due to FIVs was extremely small and well within the allowable levels based on the high-cycle endurance limit for the materials. Provide a summary of the evaluation regarding the quantity of the response and the FIV analysis with respect to the fluid elastic instability, turbulent flow and vortex shedding and acoustic resonance. Also, provide the calculated vibration level and describe the allowable limit in your acceptance criteria.

Response ME-6:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question ME-7:

In Table 5.3-2, the stress in the lower joint of the control rod drive mechanism (CRDM) canopy after the SPU will exceed the ASME Code allowable value of $3S_m$. The footnote states that the difference is insignificant. Provide the justification on how this issue was resolved.

Response ME-7:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question ME-8:

Page 5.4-3 of the application states that the computer code WESTDYN is used to perform a system analysis of reactor coolant loop (RCL) piping. Confirm whether the WESTDYN code has been reviewed and approved by the NRC. If not, provide justification for using this code.

Response ME-8:

The WESTDYN code was approved in the approval letter for WCAP-8252 Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes." The WESTDYN code was included in WCAP-8252, Revision 1 which was reviewed by the NRC and approved in a letter, dated April 7, 1981, from Robert L. Tedesco, Assistant Director for Licensing, NRC to T. M. Anderson , Manager, Nuclear Safety Department, Westinghouse.

Question ME-9:

Section 5.5.2.4 describes the acceptance criteria for the reactor coolant pump motor loading. It states that the temperature rise of the motor while driving the pump continuously under hot-loop conditions with an ambient temperature of 120°F must be in accordance with National Electrical Manufacturer's Association (NEMA) Standard MG1-20.40-1963. However, Page 5.5-6 states that the temperature rise of the motor while driving the pump continuously under hot-loop conditions with an ambient temperature of 130°F will meet NEMA Standard MG1-20.40-1963. Explain the reason for the difference between these two temperatures.

Response ME-9:

The 120°F temperature cited in Section 5.5.2.4 is the ambient temperature given in the original equipment specifications. The sentence states "Per the original equipment specifications, the temperature rise of the motor while driving the pump continuously under hot-loop conditions with an ambient temperature of 120°F must be in accordance with the National Electric Manufacturers' Association (NEMA) Standard MG1-20.40-1963." Since the allowable containment air temperature for the plant is 130°F, the reactor coolant pump motors were also evaluated for operation with that air temperature, and shown to be acceptable. The results of this evaluation are given in Section 5.5.2.5 under the heading "Motor Ambient Temperature".

Question ME-10:

In Table 5.5-1, the T_{cold} value given for High T_{avg} does not match the value given in Table 2.1-2. Explain this discrepancy.

Response ME-10:

The value of T_{cold} (541.0°F) given for High T_{avg} in Table 2.1-2 is based on a core power of 3216 MWt with a T_{avg} of 572°F. As noted in Section 1.1 of WCAP-16212-P and WCAP-16212-NP, Entergy plans to initially operate at a power level less than 4 percent above the current power level. The value of T_{cold} (541.5°F) used for evaluation of the RCP for High T_{avg} was chosen to bound the Phase 1 uprate conditions for purposes of the RCP evaluation. As noted in Section 5.5.1, lower T_{cold} conditions are conservative. The range of temperatures given for T_{cold} in Table 5.5-1 and used for the evaluations of the reactor coolant pumps thus envelopes the range of T_{cold} values given in Table 2.1-2.

Question ME-11:

With regard to Section 5.6.1 of the application, provide an evaluation for the effect of FIV on the SG steam dryer, and dryer supports with respect to the fluid-elastic instability, acoustic loads, turbulence and vortex shedding due to the increased steam flow for the power uprate.

Response ME-11:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively..

Question ME-12:

Section 5.9.1 of the application states that IP3 has a Model 44F pressurizer. However, a Model D series 84 pressurizer was used in the design-basis analysis for IP3. Model D series 84 pressurizer has the same dimensions and materials as the Model 44F. Discuss the applicability of using the base analysis of a Model D pressurizer to the IP3 Model 44F pressurizer considering the structural characteristics between these two models including supports and structural natural frequencies.

Response ME-12:

IP3 evaluation used a Model D Series 84 Pressurizer as a basis. Model 44F and Model D Series 84 Pressurizers have the same geometry, materials, and support configurations, therefore the structural natural frequencies are also the same.

REACTOR VESSEL, PRESSURIZER, AND STEAM GENERATOR STRUCTURAL INTEGRITY

Question SI-1:

In its June 16, 2004, response to a request for additional information on the IP2 SPU, the licensee provided information, in part, regarding pressure vessel materials (PVM). In PVM question no. 1 (PVM-1), the NRC staff had requested that the licensee evaluate the impact of surveillance data on the Charpy Upper Shelf Energy (USE) of the IP2 reactor vessel (RV) beltline materials. Although the licensee will be responding to the same question for IP3, the following additional information is necessary:

Response SI-1:

The IP3 response to this RAI is provided in the response to IP2 question NL-04-073-PVM-1 in letter NL-04-145 of November 18, 2004.

Question SI-1a:

Section 5.1.1.2 of the application report indicates that the minimum inlet temperature decreased from 542.2°F to 517.2°F for SPU conditions. In response to the issues in PVM-1, the licensee needs to include an evaluation of the impact of the lower inlet temperature on the predicted Charpy USE at end of license (27.1 effective full power years at SPU conditions).

Response SI-1a:

Westinghouse's evaluations for all Reactor Vessel Integrity areas (PTS, USE, withdrawal Schedule and PT Limits) were based on IP3 maintaining Tcold at 525°F or higher. This is stated in Section 5.1.2.6. In addition, Note 12 to Table 2.1-2, states that "Actual Operation of IP3 is limited to a minimum Tcold of 525°F..." Since IP3 will not operate below 525°F, no further evaluation is required and the evaluations supplied in Section 5.1.2 remain valid with no adjustments.

Question SI-1b:

PVM-1 also requested the licensee to justify the use of a smaller flaw size for the RV outlet-nozzle-to-shell region. Table 5.9-4 of the IP3 application report indicates that smaller flaw sizes than those specified in Appendix G of Section XI of the ASME Code were used for the steam generator tubesheet and shell junction, steam outlet nozzle, and feedwater nozzle. Provide a justification for using the smaller size flaw or provide an analysis using the flaw sizes and margins described in Appendix G of the Section XI of the ASME Code.

Response SI-1b:

The PODs for the steam generator tubesheet and shell junction, steam outlet nozzle, and feedwater nozzle can be taken from EPRI Report, "Justification for the Reduction of Inspection Requirements for the Boiling Water Reactor Nozzle-to-Vessel Shell Welds And Nozzle Blend Radii (VIP-108)", R. Carter, June 2002. This report is deemed applicable as the inspection technique would be the same for Steam Generators and applicable for regions with wall-thickness less than 11 inches. As shown in the following figure, the PODs of flaws with depth greater than 0.5-inch is approximately 100% (manual OD volumetric).

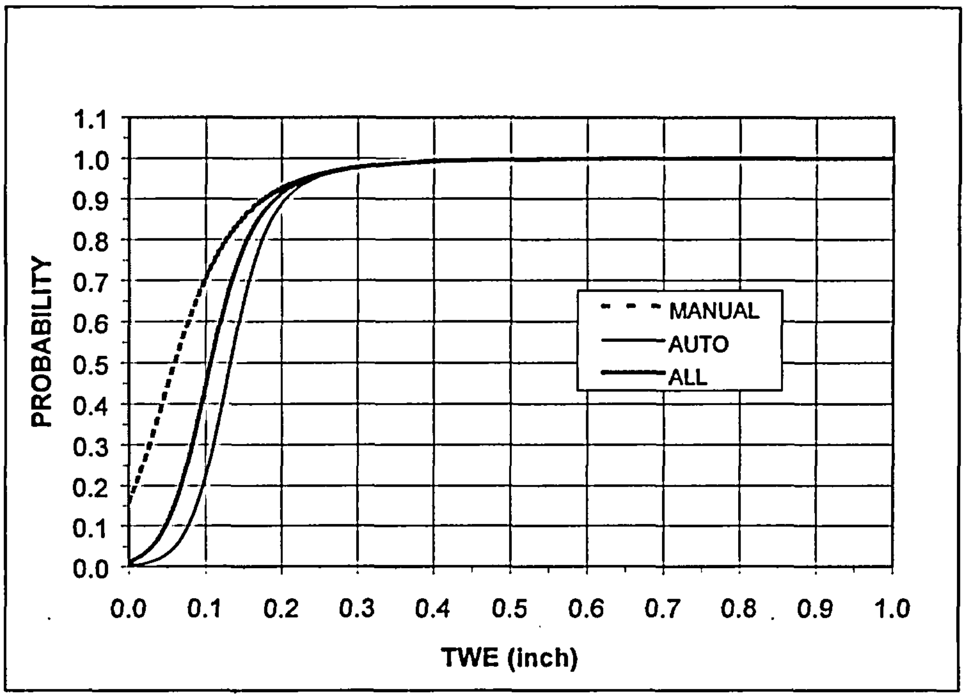


Figure SI-1b-1: Probability of Correct Rejection/Reporting (PCR) Considering Only Passed Candidates, Appendix VIII from the Outside Surface. Reporting Criterion A' = 0.15 inch.

EPRI Report, "Justification for the Reduction of Inspection Requirements for the Boiling Water Reactor Nozzle-to-Vessel Shell Welds And Nozzle Blend Radii (VIP-108)", R. Carter, June 2002

<u>Question SI-2:</u>

PVM question 2 (PVM-2) should be replaced with the following RAI:

Table 5.1.3 of the application report identifies the RTPTS values for the IP3 RV beltline materials at the end of license at SPU conditions. Section 5.1.2.2 indicates that the Pressure-Temperature (P-T) Limit Curves will be reduced by 0.7 EFPY as a result of SPU conditions. The material with the highest RTPTS value at end of license at SPU conditions is Lower Shell Plate B2803-3 with an RTPTS value of 262°F, using surveillance data, and 268°F, based on its chemical composition. This material also has the highest adjusted reference temperature (ART) in the P-T Limit Curve evaluation. The RTPTS and ART values were determined using the methodology contained in Regulatory Guide (RG) 1.99, Revision 2. This guide indicates that the procedures are valid for nominal irradiation temperature of 550°F and irradiation below 525°F should be considered to produce greater embrittlement.. Since the licensee proposes to reduce the inlet temperature to 517.2°F, the licensee must determine the impact that operating with inlet temperatures below 525°F has on the RTPTS and ART values.

Provide the surveillance data for Plate B2803-3 and include a credibility evaluation of the surveillance data in accordance with RG 1.99, Revision 2. Identify the mean inlet temperature and peak RV neutron fluence for each cycle of RV operation (include data from cycles prior to SPU and projected for post SPU conditions). Identify the mean inlet temperature for each surveillance capsule. Provide an evaluation of the impact of the lower inlet temperature on the predicted RTPTS and ART values for this plate and all other materials in the IP3 RV beltline. Describe how this evaluation impacts the P-T Limit Curves. Identify how the inlet temperature will be monitored during SPU conditions to confirm that the projected RTPTS and ART values remain valid for operation at SPU conditions.

In addition, if SPU conditions result in a change in the period of applicability for the P-T Limit Curves, the P-T Limit Curves must be submitted for staff review as part of the TS amendment process.

Response SI-2:

As stated in the response for RAI SI-1a, IP3 will not operate below 525°F (See note 12 of Table 2.1-2 of WCAP-16212-P and WCAP-16212-NP). Therefore, there is no need to evaluate the impact of temperature lower than 525°F on the RVI evaluations (i.e., PTS, USE, PT Limit curves, etc.). The credibility evaluation is contained in Appendix D of WCAP-16251-NP. This WCAP report also contains the surveillance data for Plate B2803-3.

Question SI-3:

Section 5.1.2.1 of the application report indicates that a fifth surveillance capsule must be withdrawn to satisfy regulatory requirements and that the withdrawal schedule is presented in Table 5.1-2. This table provides options for withdrawal of the fifth capsule; but, does not specify the date of capsule withdrawal. Appendix H to 10 CFR Part 50 requires that the withdrawal schedule be submitted and approved prior to implementation. Provide the date for withdrawal of the fifth capsule and describe how it complies with regulatory requirements.

Response SI-3:

Table 5.1-2 identifies an EFPY range that would satisfy acceptable times to remove the next surveillance capsule from IP3. Entergy has planned the capsule removal for Outage RF17 (scheduled for ~ 2013) which is within the range provided in note 5 to Table 5.1-2 of WCAP-15212-P. The acceptable range complies with ASTM E185-82 because the projected fluence on the last capsule will be between 9.22×10^{18} n/cm^2 (1 times the peak EOL vessel fluence) and 1.844×10^{19} n/cm^2 (2 times the peak EOL vessel fluence), depending on the exact withdrawal time. As indicated in note 6 to Table 5.1-2, withdrawal of the last capsule may be rescheduled for a later outage if life extension is approved by NRC.

PIPING

Question PIP-1:

In Section 5.10.4, "Change in PWSCC [Primary Water Stress Corrosion Cracking] Susceptibility of RVHP [Reactor Vessel Head Penetrations]," the licensee uses the RV upper head best-estimate mean fluid maximum service temperature for the purpose of determining the change in PWSCC susceptibility. The NRC staff does not find this calculation using the mean fluid temperature conservative. The staff finds that using the RV upper head maximum temperature to determine the maximum change in the PWSCC susceptibility value would be appropriate and conservative. Therefore, the licensee should update Table 5.10-1 and perform the change in PWSCC susceptibility calculation with appropriate data inputs.

Response PIP-1:

Refer to licensee response to "Question NL-04-121-NRC Item 8", regarding primary water stress corrosion cracking, provided in Entergy letter NL-04-155 dated December 15, 2004.

Question PIP-2:

In Section 5.10.6, "Conclusions," the licensee states "The increase in PWSCC susceptibilities of Alloy 600 RVHP and hot-leg nozzle weld locations (22 and 9 percent) indicated above is not considered significant since the absolute susceptibility of these locations is estimated to be very low (~10-11)." The staff finds the ~10-11 value to be inconsistent with industry inspection results and analysis performed in Material Reliability Program (MRP) Reports MRP-105, "Materials Reliability Program Probabilistic Fracture Mechanics Analysis of PWR Reactor Pressure Vessel Top Head Nozzle Cracking" and MRP-110, "Materials Reliability Program Reactor Vessel Closure Head Penetration Safety Assessment for U.S. PWR Plants."

a. Provide the basis for this estimated absolute susceptibility value.

b. What other actions will the licensee take to address the increase in PWSCC susceptibilities of Alloy 600 RVHP and hot-leg nozzle weld locations of 22% and 9%, respectfully?

c. What augmented inspections will be performed by the licensee on Alloy 182/82 welds in the reactor coolant pressure boundary hot leg?

Response PIP-2:

Refer to licensee response to "Question NL-04-121-NRC Item 8", regarding primary water stress corrosion cracking, provided in Entergy letter NL-04-155 dated December 15, 2004.

FLOW-ACCELERATED CORROSION PROGRAM

Question FAC-1:

Section 10.3, "Flow-Accelerated Corrosion [FAC] Program," states that the CHECWORKS™ program is used to predict erosion rates for several large-bore high energy piping systems.

Question FAC-1a:

Describe the criteria used in for selecting components for modeling using the CHECWORKS™ Program.

Response FAC-1a:

The Checworks model is a mathematical representation of IP3's FAC susceptible lines and systems. For a component to be included in the IP3 Checworks model, it must possess criteria that permit accurate modeling.

The criteria used to determine if a line and its associated components are susceptible to FAC are specified in Section 4.2.2 of NSAC-202L-R2 "Recommendations for an Effective Flow-Accelerated Corrosion Program". Based on these criteria, lines are considered susceptible to FAC unless they meet the exclusion criteria specified. The criteria are based on the following parameters:

- Material
- Steam Quality
- Dissolved Oxygen Content
- Operating Temperature (for single-phase lines)
- Frequency of Operation

The criteria used to determine if a susceptible line can be modeled in Checworks are specified in "CHECWORKS Steam/Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data", Final Report, September 2004. Based on these criteria, lines are considered modelable unless they meet the exclusion criteria specified. The exclusion criteria are based on the following:

- Lines with unknown or varying operating conditions
- Piping that is visually inspected
- Lines with localized susceptibility
- Lines with high steam quality/low wear rate (where Checworks would predict near-zero wear)
- Lines with operating conditions outside Checworks modeling capabilities (entrained moisture or non-condensable gases)
- Socket-welded piping

When the above criteria can be quantified, and the line and its associated components are determined to be susceptible to FAC, the line was included in the IP3 Checworks model. Systems that are currently modeled in Checworks at IP3 include Extraction Steam, Condensate, Feedwater, Heater Drains, Reheater Drains, Moisture Separator Drains, and Preseparator Drains.

Question FAC-1b:

Describe the criteria for repair or replacement of components that become damaged as a result of FAC.

Response FAC-1b:

Using the inspection results, the wear rate and predicted thickness at a future inspection date, usually the next refueling outage, is calculated. If the predicted thickness is greater than or equal to 87 ½ % of the component nominal thickness (Tnom), the component is acceptable for continued service. The 87 ½ % of Tnom represents the thinnest pipe wall allowed by the pipe manufacturer's tolerances (± 12 ½ % Tnom). If the predicted thickness is less than or equal to 30% of Tnom, for safety related piping or 20% of Tnom for non-safety related piping, the component is to be repaired or replaced prior to continued operation.

For instances when the predicted thickness is between the two extreme cases (87 ½% and 30% (or 20%) of Tnom), a structural evaluation is required. The structural evaluation is to satisfy the pipe code stress requirements. Based on the structural evaluation, if the component meets the stress requirements for the predicted wall thickness at the end of the operating cycle, the component is acceptable for continued operation. For localized defects, a local wall thinning evaluation, using the methods described in the applicable ASME Code Cases may also be performed to determine the structural capabilities of the thinned component using the predicted wall thickness for the end of the operating cycle. Components that are found to be unacceptable for continued operation by either of the above two methods, are repaired or replaced prior to continued operation.

Question FAC-1c:

For the five components most susceptible to FAC, provide numerical data that show changes in: (1) velocity, (2) temperature, and (3) predicted wear rate that result from the SPU.

Response FAC-1c:

An analysis was performed on a sample of some of the components in the model most susceptible to FAC. These components were found by selecting the five components with the highest wear rates for the pre-uprate power level and the five components that experienced the greatest percent increase of wear rate due to the SPU.

Results are shown in attached tables (Table FAC-1c-1 and Table FAC-1c-2.)

Table FAC-1c-1

Component	Wear Rate Analysis Run	Flow (Mlb/hr)			Temperature (deg F)			Wear Rate (mils/yr)			Most Susceptible (Pre-SPU)	Greatest Change
		Original	SPU	Change	Original	SPU	Change	Original	SPU	Change		
EX-05.1A-01N	ES: LP TO 32 HEATERS	0.408	0.476	16.5%	196.5	206.9	10.4	35.67	26.66	-25.3%	1	
EX-05.1A-04N	ES: LP TO 32 HEATERS	0.408	0.476	16.5%	196.5	206.9	10.4	23.87	17.89	-25.1%	2	
EX-05.2A-02E	ES: LP TO 32 HEATERS	0.408	0.476	16.5%	196.5	206.9	10.4	22.38	17.01	-24.0%	3	
EX-05.1A-03E	ES: LP TO 32 HEATERS	0.408	0.476	16.5%	196.5	206.9	10.4	20.33	15.45	-24.0%	4	
EX-05.2A-05E	ES: LP TO 32 HEATERS	0.408	0.476	16.5%	196.5	206.9	10.4	19.17	14.57	-24.0%	5	
EX-04.21-02P	ES: LP TO 33 HEATERS	0.476	0.473	-0.7%	246.1	254.8	8.7	4.10	11.97	192.1%		1
EX-04.6-07T	ES: LP TO 33 HEATERS	0.476	0.473	-0.7%	246.1	254.8	8.7	4.10	11.98	192.1%		2
EX-04.6-02P	ES: LP TO 33 HEATERS	0.476	0.473	-0.7%	246.1	254.8	8.7	4.10	11.97	192.0%		3
EX-04.13-07T	ES: LP TO 33 HEATERS	0.476	0.473	-0.7%	246.1	254.8	8.7	4.11	11.98	191.8%		4
EX-04.13-02P	ES: LP TO 33 HEATERS	0.476	0.473	-0.7%	246.1	254.8	8.7	4.11	11.98	191.8%		5

Table FAC-1c-2

Component	Wear Rate Analysis Run	Most Susceptible (Pre-SPU)	Greatest Change	Notes
EX-05.1A-01N	ES: LP TO 32 HEATERS	1		Typical of 6 outlet nozzles in this Wear Rate Analysis run with the highest wear rate.
EX-05.1A-04N	ES: LP TO 32 HEATERS	2		Typical of 6 inlet nozzles in this Wear Rate Analysis run with the highest wear rate.
EX-05.2A-02E	ES: LP TO 32 HEATERS	3		Typical of 3 90 deg elbows (w/in 1 pipe diameter of upstream fitting) in this Wear Rate Analysis run with the highest wear rate.
EX-05.1A-03E	ES: LP TO 32 HEATERS	4		Typical of 6 45 deg elbows (w/in 1 pipe diameter of upstream fitting) in this Wear Rate Analysis run with the highest wear rate.
EX-05.2A-05E	ES: LP TO 32 HEATERS	5		Typical of 3 45 deg elbows in this Wear Rate Analysis run with the highest wear rate.
EX-04.21-02P	ES: LP TO 33 HEATERS		1	
EX-04.6-07T	ES: LP TO 33 HEATERS		2	
EX-04.6-02P	ES: LP TO 33 HEATERS		3	
EX-04.13-07T	ES: LP TO 33 HEATERS		4	Typical of 2 type-15 tees in this Wear Rate Analysis run with the highest change in wear rate.

Question FAC-2:

Section 10.3 also states that the IP3 Small Bore and Augmented Monitoring Program is used to address piping that has not been modeled using CHECWORKS™ program.

Question FAC-2a:

Describe the Small Bore and Augmented Monitoring Program in more detail. Describe the criteria (in addition to piping diameter requirements) that determines which small bore lines are included in the Program.

Response FAC-2a:

The IP3 Small-Bore and Augmented Monitoring Program includes FAC-susceptible piping that does not fall within the scope of the Large-Bore (Checworks modeled) FAC Program.

The majority of these lines are Small-Bore (<2" nominal pipe size) FAC susceptible systems that are determined by a screening process. These systems include socket-welded piping that cannot be accurately modeled using Checworks due to the many uncertainties such as unknown operating conditions, percent of usage, and fit-up gaps between piping and sockets.

In order to define the scope of the Small-Bore program, the screening process mentioned above was used to generate a list of systems determined to be susceptible to FAC. To form the list, the scope of systems to consider was defined, the operating and design conditions within those lines were determined, and the consequences of failure were considered. Then, based on FAC-susceptibility and consequences of failure, the lines were divided into four priority groups. These groups contain the lines recommended for inspection in the short, intermediate or long term, and those systems that do not require inspection.

Within each susceptible line identified above, the individual components considered most likely to be experiencing FAC-induced wall thinning were identified for inspection. These components were identified for inspection based on plant experience, industry experience and a susceptibility ranking based on geometry. Components identified based on plant experience are those that have experienced wear in the past at IP3, or sister components of those that have experienced wear. Additional components were identified for inspection based on industry-wide FAC experience. For instance, piping downstream of control valves and orifices has been observed to exhibit wear at other plants. Other industry experience indicates specific areas of concern, such as steam traps, Feedwater regulating valve bypass lines, and operating vents.

Question FAC-2b:

Describe the criteria used to include non-small bore piping into the Small Bore and Augmented Monitoring Program instead of the CHECWORKS™ program.

Response FAC-2b:

These systems are Large-Bore (>2") FAC susceptible systems that are not suitable for Checworks modeling and are identified as the Augmented part of the Small-Bore and

Augmented Monitoring Program. In general, these systems have usage and flow rates that cannot be accurately quantified because demand and operating conditions greatly vary or are controlled by a remote level, pressure, or temperature signal. These FAC susceptible systems are determined through the screening process described above for the Small-Bore piping.

Other criteria used to include non-small bore components in the Augmented Program are components downstream of control valves, high level dump lines, bypass lines, discharge nozzles, orifices, areas with concentrated geometry changes, and normally closed valves with a potential or history of leakage.

Question FAC-2c:

Describe how the Small Bore and Augmented Monitoring Program predicts erosion rates in small bore lines.

Response FAC-2c:

After a small-bore component is inspected, a wall thinning calculation is performed per ENN-DC-133, "Structural Evaluation of Wall Thinning in Carbon and Low Alloy Steel Piping". This calculation determines the wear (determined by trending or using the band, area, blanket or point-to-point method), the minimum wall thickness required by code, the wear rate, and a prediction of the remaining service life of the component.

The component's remaining service life is then tracked in the "Summary of Calculations to Date" list. From this list, the components for inspection are selected by performing a sort of the list to identify components that have a remaining service life with less than a full operating cycle after the next two outages. Inspecting these components at this time will allow sufficient time for planning of the repair or replacement of the component if it is continuing to wear as predicted.

PROTECTIVE COATINGS PROGRAM

Question PCP-1:

The NRC staff notes that the application did not include a description of the Protective Coatings Program at IP3.

Question PCP-1a:

Describe the Protective Coatings Program for IP3.

Response PCP-1a:

The coatings program at Indian Point 3 is in conformance with NRC Regulatory Guide 1.54 and ANSI N101.4-72. Procedure TS-MS-013 governs the specification of coatings, including Service Level 1 (Cat. I). Procedures SYS-004-GEN, "Qualification of Coating Application Personnel", SYS-005-GEN, "Application of Protective Coating" and SYS-006-GEN, "Coatings Storage and Handling" govern the installation and storage of coatings.

Question PCP-1b:

Discuss in general terms how the SPU affects the Protective Coatings Program.

Response PCP-1b:

The Service Level 1 coatings at IP3 will continue to be bounded by the DBA parameters specified in ANSI N101.2

Question PCP-1c:

Discuss how the qualification of the Service Level 1 coatings are impacted by SPU temperature and pressure conditions.

Response PCP-1c:

The Service Level 1 coatings used at Indian Point 3 are qualified to the standard PWR DBA temperature/pressure curves. The SPU design-basis accident (DBA) conditions are bounded by the standard curves, therefore the qualification of the Indian Point 3 Service Level 1 coatings are not affected by SPU pressure or temperature conditions.

Question PCP-1d:

Discuss whether the qualification parameters (e.g., temperature, pressure, etc.) for your Service Level 1 coatings will continue to be bounded by SPU design- basis accident (DBA) conditions.

Response PCP-1d:

Since the Service Level 1 coatings used at Indian Point 3 are qualified to the standard PWR DBA temperature/pressure curves and the SPU design-basis accident (DBA) conditions are bounded by the standard curves, there is no effect on the qualification parameters of the coatings.

Question PCP-1e:

Describe the actions that will be taken if the qualification of Service Level 1 coatings are not bounded by the SPU/DBA conditions, since coating failure could threaten performance of the ECCS sump after a LOCA.

Response PCP-1e:

No actions need to be taken for the qualification of the Indian Point 3 Service Level 1 coatings because the SPU design-basis accident (DBA) conditions are bounded by the standard PWR DBA temperature/pressure curves.

STEAM GENERATOR STRUCTURAL INTEGRITY EVALUATION

Question SG-1:

The conclusions for mechanical plugs in Section 5.6.4 states that "... both the long and short mechanical plug designs satisfy all applicable stress and retention acceptance criteria at the SPU operating conditions with up to 10-percent SGTP [steam generator tube plugging]." The results subsection states that "The plug meets the Class 1 fatigue exemption requirements per N-415.1 of the ASME Code ..."

Question SG-1a:

Provide a table (similar to Table 5.6-2 for the primary and secondary side components) which summarizes the load conditions, stress categories, ASME allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the mechanical plugs. Show the calculation results which indicate that ASME Code allowables were met.

Response SG-1a:

The response to this question was provided in tables in letter NL-04-145 of November 18, 2004, in Attachments 3 (proprietary) and 4 (non-proprietary) in response to IP2 item Question NL-04-073-SG-2 (Table NL-04-073-SG-2-1 Mechanical Plug Stress Summary and Table NL-04-073-SG-2-2 Mechanical Plug Retention.)

Question SG-1b:

Provide calculation results which show that the mechanical plugs are qualified for the SPU condition with up to 10% tube plugging.

Response SG-1b:

The analysis performed for the mechanical plugs covered two power uprate projects. The first being a 1.4% MUR plant uprate with a 24% tube plugging. The second is the 4.85% SPU condition with a 10% tube plugging. The values that are presented in the responses to RAI SG-1a and SG-1c envelop both IP3 uprates. The work performed for the 4.85% SPU project does not cover tube plugging greater than 10%. In the conclusions of the mechanical plugs portion of Section 5.6.4 it states that, "Results of the analyses performed for the mechanical plug for IP3 show that both the long and short mechanical plug designs satisfy all applicable stress and retention acceptance criteria at the SPU operating conditions with up to 10% SGTP."

Question SG-1c:

Provide the basis and calculation results (if any) for satisfying the ASME Class 1 fatigue exemption requirements.

Response SG-1c:

The response to this question was provided in a table in letter NL-04-145 of November 18, 2004, in Attachments 3 (proprietary) and 4 (non-proprietary) in response to IP2 item Question

NL-04-073-SG-2 (Table NL-04-073-SG-2-3 Mechanical Plug Fatigue Evaluation based on Fatigue Exemption rules of ASME code Section N-474-1.)

Question SG-2:

The conclusions for shop welded plugs in Section 5.6.4 states that "[a]ll primary stresses are satisfied for the weld between the weld plug and the tubesheet cladding," and "[t]he overall maximum primary-plus-secondary stresses for the enveloping transient case of 'loss-of-load' was determined to be acceptable," and "[i]t was determined that the fatigue exemption rules were met, and therefore, fatigue conditions are acceptable."

Question SG-2a:

Provide a table (similar to Table 5.6-2 for the primary and secondary side components) that summarizes the load conditions, stress categories, ASME Code allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the shop weld plugs. Show the calculation results which indicate that ASME Code allowables were met.

Response SG-2a:

The response to this question contains proprietary information. The proprietary and non-proprietary versions of the response are provided in Attachments 3 and 4 of this letter, respectively.

Question SG-2b:

Provide the basis and calculation results (if any) for satisfying the ASME Code fatigue exemption requirements.

Response SG-2b:

The response to this question was provided in a table in letter NL-04-145 of November 18, 2004, in Attachments 3 (proprietary) and 4 (non-proprietary) in response to IP2 item Question NL-04-073-SG-3 (Table NL-04-073-SG-3-2 Shop Welded Plug Fatigue Evaluation based on Fatigue Exemption rules of ASME code Section N-474-1.)

ATTACHMENT 4 TO NL-04-156

ADDITIONAL INFORMATION FOR IP3 SPU LICENSE AMENDMENT REQUEST

BASED ON NRC RAIs ISSUED NOVEMBER 5, 2004

Non-Proprietary version of responses containing proprietary information (from Westinghouse transmittal PU3-W-04-163)

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

Question RSA-2:

Regarding the charging and volume control system (CVCS) malfunction re-analysis:

Question RSA-2-1:

The licensee assumes complete mixing of the diluted water injected through the cold leg with the active volumes in the RCS. Explain how a dilution front is addressed in the analysis for each plant mode and how a local power spike in the reactor core is precluded.

Response RSA-2-1:

The response to RAI RSA 2-1 is non-proprietary. See Attachment 2 for the response.

Question RSA-2-2:

The IP3 Final Safety Analysis Report states the reactor coolant system (RCS) volume assumed in the analysis was 8,630 ft^3 for Modes 1 and 2. However, the volume in the application report is 9,350 ft^3 for Modes 1 and 2. Provide the justification for the change in RCS volume used in the analyses. Was the methodology used for the SPU analysis consistent with the analysis of record?

Response RSA-2-2:

There are several reasons for the increase in the RCS active volume assumed for Modes 1 and 2 for the CVCS malfunction re-analysis. First, the RCS active volume of 8630 ft^3 that was used in the analysis of record that was performed in 1993 was propagated forward from the previous analysis performed in 1988 because it was determined in the 1993 analysis that this value continued to be conservatively low. At the time the 1988 analysis was performed, the volume of the pump suction leg (the portion of the cold leg between the SG and the pump), [ ]^{a,c} ft^3 ([ ]^{a,c} ft^3/loop), was inadvertently excluded from the RCS active volume. However, since the pump suction legs should be included in the calculation of the RCS active volume for Modes 1 and 2, these volumes have been incorporated into the calculation of the RCS active volume for the SPU.

Second, the 1988 analysis inadvertently doubled the volumes associated with the vessel inlet and outlet nozzles, [ ]^{a,c} ft^3 ([ ]^{a,c} ft^3/loop), in the calculation of the RCS active volume. Although doubling these volumes is non-conservative, it was considered to be acceptable at that time since it was more than offset by the exclusion of the pump suction legs. These volumes have not been doubled in the calculation of the RCS active volume for the SPU.

Third, there has been a decrease in the maximum SGTP level assumed from the previous value of 24% to the value of 10% assumed for the SPU. This decrease in SGTP would have a net effect of an increase of approximately [ ]^{a,c} ft^3 ([ ]^{a,c} ft^3/loop) on the RCS active volume.

Finally, as a result of some other minor changes in modeling assumptions over the years, the calculated volumes for the reactor vessel and SG tubes have changed slightly, which caused a net decrease in the RCS active volume by approximately [ ]^{a,c} ft^3.

In summary, the differences between the RCS active volume calculated for the SPU (9350 ft^3) and that presented in Chapter 14.1.5 of the IP3 FSAR (8630 ft^3) can be attributed to the exclusion of the pump suction legs and doubling of the vessel inlet and outlet nozzles in the 1988 analysis, a decrease in the maximum SGTP as part of the SPU, and a net decrease in the

RCS active volume due to changes in the calculated volumes for the reactor vessel and SG tubes.

8630 ft^3 (1988 / 1993 analysis)
[ ]a,c
[ ]a,c
[ ]a,c
[ ]a,c
9350 ft^3 (SPU analysis)

Consistent with previous IP3 analyses, the volume associated with the reactor vessel upper head has conservatively been excluded in the SPU. As such, the RCS active volume that was calculated for the SPU is still overly conservative by approximately [ ]a,c ft^3.

Question RSA-7:

Regarding the complete loss-of-reactor-coolant flow transient analysis:

Question RSA-7-1:

The licensee assumed an undervoltage trip time delay of 1.5 seconds. Explain the reason for the time delay and why this is a conservative assumption in the analysis.

Response RSA-7-1:

For a Westinghouse-designed plant, 1.5 seconds is a typical value for this delay. A typical breakdown of the time delay is as follows.

Undervoltage trip circuitry including
[ ]a,c second
[ ]a,c second
[ ]a,c second
[ ]a,c second
TOTAL DELAY TIME 1.50 seconds

This breakdown is typical and only the total time is used in the analysis. This assumption, which is consistent with the current analysis of record for IP3, is considered conservative because surveillance tests are in place to ensure that the assumed values of adjustable delay and trip breaker opening times bound the measured plant value.

Note that the analysis conservatively assumes that the pump coastdown begins at time zero, even though, in reality, pump speed will not be reduced as the emf decays to the undervoltage setpoint.

Question RSA-7-2:

The licensee assumed rod motion occurs at 1.6 seconds, following a 0.6 second underfrequency trip time delay. Explain the reason for the time delay and why this is a conservative assumption in the analysis.

Response RSA-7-2:

For a Westinghouse-designed plant, 0.6 seconds is a typical value for this delay. A typical breakdown of the time delay is as follows.

Underfrequency trip circuitry including
[ ]^{a,c} second
[ ]^{a,c} second
[ ]^{a,c} second
TOTAL DELAY TIME 0.60 second

This breakdown is typical and only the total time is used in the analysis This assumption, which is consistent with the current analysis of record for IP3, is considered conservative because surveillance tests are in place to ensure that the assumed values of adjustable delay and trip breaker opening times bound the measured plant value.

Question RSA-9:

Section 6.3.1 of the application report describes the revised instrumentation ranges for RCS temperature measurement chosen for IP3 after implementation of the SPU to ensure proper operation of the OTΔT and OPΔT reactor trip functions over a realistic full power operating T_{avg} range of 562.0°F to 572.0°F as follows:

520°F $\leq T_{cold} \leq$ 640°F
540°F $\leq T_{avg} \leq$ 615°F
520°F $\leq T_{hot} \leq$ 640°F

These revised instrumentation ranges are said to be derived from the instrumentation ranges for proper operation of the OTΔT and OPΔT functions over the entire range (T_{avg} from 549.0°F to 572.0°F) and a reduced, more realistic range (T_{avg} from 562.0°F to 572.0°F), respectively, of applicable full power operating RCS temperatures. Please provide a more detailed explanation of how these revised instrumentation ranges are derived.

Response RSA-9:

The RCS temperature measurement ranges noted above are required to ensure that the OTΔT and the OPΔT reactor trip functions are OPERABLE over the range of conditions expected to occur during normal at-power operation and during any Condition I or II event such that the DNB and fuel centerline melting design basis are satisfied. The RCS temperature measurement ranges are defined by the intersection points of the OTΔT and the OPΔT reactor trip functions and the lines representing the OTΔT and the highest steam generator safety valve (SGSV) setpoint.

[ ]a,c

Westinghouse Non-Proprietary Class 3

a,c

a,c

Figure RSA-9-1 Four Intersection Points for a Full Power Operating T_{avg} of 572°F

Question RSA-11:

Footnote 7 of Table 2.1-2 in the application report indicates that the RCS minimum measured flow of 364,700 gpm includes a 2.9% flow measurement uncertainty. Attachment I to the June 3 application regarding the proposed TS changes states that the SPU flow measurement uncertainty was calculated using the existing methodology described in WCAP-11397-P-A, and remains at the current value of 2.9%. Since WCAP-11397-P-A simply uses, rather than calculates, the RCS flow measurement uncertainty value, provide the calculation that shows the 2.9% RCS flow measurement uncertainty is applicable for use at IP3 under SPU conditions.

Response RSA-11:

See information below

Calorimetric RCS Flow Measurement With Feedwater Venturis

For the calorimetric RCS flow measurement and the use of the feedwater venturis for measurement of feedwater flow, the thermal output of each steam generator is determined by a secondary side calorimetric power measurement. The feedwater flow is determined by multiple delta-p measurements and the following calculation:

$$W_{fw} = (K_{fw})(F_{a,fw})\{(\rho_{fw})(\Delta p_{fw})\}^{1/2} \qquad \text{Eq. 7}$$

where;

W_{fw}	=	Feedwater flow (lb/hr)
K_{fw}	=	Feedwater venturi flow coefficient
$F_{a,fw}$	=	Feedwater venturi correction for thermal expansion
ρ_{fw}	=	Feedwater density (lb/ft^3)
Δp_{fw}	=	Feedwater venturi pressure drop (inches H_2O).

The feedwater venturi flow coefficient is the product of a number of constants including as-built dimensions of the venturi and calibration tests performed by the vendor. The thermal expansion correction is based on the coefficient of expansion of the venturi material and the difference between feedwater temperature and calibration temperature. Feedwater density is based on the measurement of feedwater temperature and feedwater pressure. The venturi pressure drop is obtained from the output of the differential pressure transmitter connected to the venturi.

The calorimetric RCS flow measurement is thus based on the following plant measurements:

Steamline pressure (P_S)
Feedwater temperature (T_{fw})
Feedwater pressure (P_{fw})
Feedwater venturi differential pressure (Δp_{fw})
Hot Leg temperature (T_H)

Cold Leg temperature (T_C)
Pressurizer pressure (P_p)
Steam Generator blowdown (W_{bd})(if not secured)

And on the following calculated values:

Feedwater venturi flow coefficient (K_{fw})
Feedwater venturi thermal expansion correction ($F_{a,fw}$)
Feedwater density (ρ_{fw})
Feedwater enthalpy (h_{fw})
Steam enthalpy (h_s)
Moisture carryover (impacts h_s)
Primary system net heat losses (Q_L)
RCP heat addition (Q_P)
Hot leg enthalpy (h_H)
Cold leg enthalpy (h_C).

The derivation of the measurement uncertainties and flow uncertainties on Table 5b are noted below.

Secondary Side

As stated previously, the secondary side uncertainties are in three principal areas, feedwater flow, feedwater enthalpy, and steam enthalpy. These areas are specifically identified on Table 5b.

For the measurement of feedwater flow, each feedwater venturi is calibrated by the vendor in a hydraulics laboratory under controlled conditions to an accuracy of [$]^{a,c}$. The calibration data that substantiates this accuracy is provided to the plant by the vendor. An additional uncertainty factor of [$]^{a,c}$ is included for installation effects, resulting in a conservative overall flow coefficient (K_{fw}) uncertainty of [$]^{a,c}$. Since RCS loop flow is proportional to steam generator thermal output that is proportional to feedwater flow, the flow coefficient uncertainty is expressed as [$]^{a,c}$. It should be noted that no allowance is made for venturi fouling. The venturis should be inspected, and cleaned if necessary, prior to performance of the calorimetric measurement. If fouling is present but not removed, it's effects must be treated as a flow bias.

The uncertainty applied to the feedwater venturi thermal expansion correction ($F_{a,fw}$) is based on the uncertainties of the measured feedwater temperature and the coefficient of thermal expansion for the venturi material, usually 304 stainless steel. For this material, a change of ±1°F in the nominal feedwater temperature changes $F_{a,fw}$ by [$]^{a,c}$ and the steam generator thermal output by the same amount.

An uncertainty in $F_{a,fw}$ of [$]^{a,c}$ for the material variance of the composition of 304 stainless steel is used in this analysis. This results in an additional uncertainty of [$]^{a,c}$ in feedwater flow. Westinghouse uses the conservative value of [$]^{a,c}$ in the uncertainty calculation.

Feedwater venturi Δp_{fw} uncertainties are converted to % feedwater flow using the following conversion factor:

$$\%\ \text{flow} = (\Delta p\ \text{uncertainty})(1/2)(\text{transmitter span}/\ 90)^2 \qquad \text{Eq. 8}$$

The feedwater flow transmitter span is [ ]^{a,c} nominal flow.

Primary Side

As stated previously, the primary side uncertainties are in four principal areas, hot leg enthalpy, cold leg enthalpy, cold leg specific volume, and RCP heat addition. These are specifically noted on Table 5b.

Using Table 5b, the 4-loop uncertainty equation is as follows:

[ ]^{a,c}

or

[ ]^{a,c}

Based on the number of loops and instrument uncertainties for the various parameters, the flow uncertainty is:

# of loops	flow uncertainty (% flow)	
4	[ ]^{a,c}	random
		bias

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TABLE 3b - CALORIMETRIC RCS FLOW INSTRUMENTATION UNCERTAINTIES (with Venturis)

(% SPAN)	FW TEMP[a]	FW PRESS[b]	FW FLOW[c]	STM PRESS[d]	T_H[e]	T_C[e]	PRZ PRESS[f]	
PMA =								a,c
SRA =								
SCA =								
SMTE =								
SPE =								
STE =								
SD =								
BIAS =								
RRA =								
RCA =								
RMTE =								
RTE =								
RD =								
PS =								
NON-LIN								
CA =								
MTE =								
TE =								
D =								
RDOUT =								
CSA =								
# OF INSTRUMENTS USED	1/Loop	1/Loop	1/Loop	3/Loop	3/Loop	1/Loop	4	
	°F	psig	% dp	psig	°F	°F	psig	
INST SPAN =	568	1500	106.4% flow	1400	120	120	800	
INST UNC. (RANDOM) =								a,c
INST UNC. (BIAS) =								
NOMINAL =	433.6	887 psia	90% flow	787 psia	603.0	541.0	2250 psia	

a. Feedwater temperature is measured by a thermocouple on each loop, and read by the plant computer.
b. Feedwater pressure is measured by a transmitter on each loop, and read by the plant computer or indicator.
c. Feedwater flow is measured by a venturi and Δp indicator on each loop, and read by the plant computer.
d. Steam pressure is measured by transmitters on each loop, and read by the plant computer or indicator.
e. Thot and Tcold are measured by RTDs on each loop, and read by digital voltmeters at test points in the racks.
f. Pressurizer pressure is measured by transmitters, and read by indicators.
* Provided by Entergy

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TABLE 4b - CALORIMETRIC RCS FLOW SENSITIVITIES (with Venturis)

Feedwater Flow

		a,c
$F_{a,fw}$		
Temperature	=	
Material	=	
Feedwater Density		
Temperature	=	
Pressure	=	
ΔP	=	
Feedwater Enthalpy		
Temperature	=	
Pressure	=	

h_s	=	1199.4	Btu/lbm
h_f	=	412.2	Btu/lbm
$\Delta h(SG)$	=	787.2	Btu/lbm

		a,c
Steam Enthalpy		
Pressure	=	
Moisture	=	
Hot Leg Enthalpy		
Temperature	=	
Pressure	=	

h_H	=	617.0	Btu/lbm
h_C	=	535.8	Btu/lbm
$\Delta h(VESS)$	=	81.3	Btu/lbm

		a,c
Cold Leg Enthalpy		
Temperature	=	
Pressure	=	

		a,c
Cold Leg Specific Volume		
Temperature	=	
Pressure	=	

TABLE 5b - CALORIMETRIC RCS FLOW MEASUREMENT UNCERTAINTIES

(with Venturis)

Component	Instrument Uncertainty	Flow Uncertainty (% flow)
		a,c
Feedwater Flow		
Venturi (FW_v)		
Thermal Expansion Coefficient		
Temperature ($F_{a,fw/t}$)		
Material ($F_{a,fw/m}$)		
Density		
Temperature (ρ_t)		
Pressure (ρ_p)		
ΔP ($FW_{\Delta p}$)		
Feedwater Enthalpy		
Temperature (h_t)		
Pressure (h_p)		
Steam Enthalpy		
Pressure (h_{sp})		
Moisture ($h_{s\ moist}$)		
Net Pump Heat Addition (NPHA)		
Hot Leg Enthalpy		
Temperature (h_{Ht})		
Streaming, loop (h_{Hsl})		
Streaming, system (h_{Hss})		
Pressure (h_{Hp})		
Cold Leg Enthalpy		
Temperature (h_{Ct})		
Pressure (h_{Cp})		
Cold Leg Specific Volume		
Temperature (vc_t)		
Pressure (vc_p)		
Flow Bias Total Value		
		a,c
4 Loop Uncertainty (random)		
4 Loop Uncertainty (bias)		

*, **, +, ++ Indicates sets of dependent parameters

Loop RCS Flow Measurement Uncertainty

As noted earlier, the calorimetric flow measurement is used as the reference for the normalization of the loop RCS flow indicators from the cold leg elbow tap Δp transmitters. The required Technical Specification surveillance can then be performed by reading the loop RCS flow indicators. Table 6 notes the instrument uncertainties for normalization of the loop RCS flow indicators, assuming 2 loop RCS flow channels per RCS loop. The Δp transmitter uncertainties are converted to % flow using the following conversion factor:

$$\% \text{ flow} = (\Delta p \text{ uncertainty})\ (1/2)\ (\text{transmitter span}/100)^2 \qquad \text{Eq. 9}$$

The loop RCS flow transmitter span is 120% nominal flow.

The loop RCS flow channel uncertainty is then combined with the calorimetric RCS flow measurement uncertainty. Using Table 6, the uncertainty equation is as follows:

[ ]a,c

or

[ ]a,c

This combination of uncertainties results in the loop RCS flow uncertainty of ± 2.9% flow with a bias of 0.0% flow.

TABLE 6

LOOP RCS FLOW MEASUREMENT UNCERTAINTY

CONTROL BOARD INDICATORS

FOR 2 LOOP RCS FLOW INDICATORS PER REACTOR COOLANT LOOP

		% SPAN	% FLOW
PMA	=		
PEA	=		
SRA	=		
SCA	=		
SMTE	=		
SPE	=		
STE	=		
SD	=		
BIAS	=		
RCA	=		
RMTE	=		
RTE	=		
RD	=		
PS	=		
CA	=		
MTE	=		
TE	=		
D	=		
RDOUT	=		
FLOW CALORIMETRIC	=		
FLOW CALORIM. BIAS	=		
INSTRUMENT SPAN	=		120.0

a,c

LOOP RCS FLOW UNCERTAINTY = 2.9 % flow (random)
= 0.0 % flow (bias)

MECHANICAL ENGINEERING

Question ME-3:

In Table 5.1-1, the numerical value of the stress intensity for the CRDM Housings is less than the allowable American Society of Mechanical Engineers, Boiler and Pressure Vessel Code

(ASME Code), Section III value of $3S_m$. However, the equation is written to indicate that the $3S_m$ value is exceeded. This error appears to be editorial. Confirm whether our observation is valid.

Response ME-3:

This is a type. The row in the Table 5.1-1 should read:

Location	Maximum Range of Stress Intensity	a c	Cumulative Fatigue Usage Factor
CRDM Housings			0.124 < 1.0

Question ME-4:

In Table 5.1-1, the stress intensity of the reactor vessel closure studs is very close to the allowable ASME Code allowable limit. Provide a summary of the calculation of the stress intensity and the cumulative usage factors (CUFs) for the closure studs.

Response ME-4:

The calculated stresses and cumulative fatigue usage factors for the Indian Point 3 reactor vessel closure studs are provided below:

Component	Calculated Stress Range (ksi)	Allowable Stress Range (ksi)	Cumulative Fatigue Usage	
Reactor Vessel Closure Studs				
- Heatup/Unbolted		a, c 110.4		a, c
- Heatup/Cooldown		110.4		
- Hydrostatic Test at 2500 psi/Cooldown		110.4		
- Hydrostatic Test at 2500 psi (Leak Test)		110.4		
- Hydrostatic Test at 3125 psi/Leak Test		110.4		
- Loss of Load/Leak Test		110.4		
- Loss of Load/Turbine Roll Test		110.4		
- Loss of Load/SS - OBE Earthquake		110.4		
- Unit Loading/SS - OBE Earthquake		110.4		
- Unit Loading/Reactor Trip		110.4		
- Unit Loading/Loss of Load		110.4		
- Unit Loading/Partial Loss of Flow		110.4		
- Unit Loading/Large Step Load Decrease		110.4		
- Unit Loading/Unloading		110.4		
Total Cumulative Usage Factor				

Question ME-5:

Page 5.2-13 of the application states that the reactor pressure vessel internals were designed to meet the intent of Subsection NG of the ASME Code, Section III. It also states that a plant-specific stress report on the reactor pressure vessel internals was not required, and that the structural integrity of the internals has been ensured by analyses performed on both generic and plant-specific bases. Provide the calculated stresses at the uprated power level for components listed in Table 5.2-1 in comparison to the ASME Code allowed stress limits.

Response ME-5:

The calculated stresses and cumulative fatigue usage factors are provided below:

Component	Calculated Stress (ksi)	Allowable Stress (ksi)	Cumulative Fatigue Usage
Lower Core Plate	[ ]a,c	48.6	[ ]a,c
Upper Core Plate		48.6	
Lower Support Columns		47.5	
Instrumentation Columns		48.6	
Core Barrel to LSP Junction		48.6	
Thermal Shield		49.2	
Top Hat Structure			
- Reactor Trip to loss of Power		48.6	
- Reactor Trip to 10% Load Step		48.6	
- Loss of Flow to 10% Load Step		48.6	
- Large Step Load Decrease to 10% Load Step		48.6	
- Loss of Load to 10% Load Step		48.6	
- Unit Loading/Unloading		48.6	
Total Cumulative Usage Factor			[ ]a,c

* - Elastic/plastic analysis was performed.

Question ME-6:

In Section 5.2.4.2, "Flow Induced Vibration (FIV)," the licensee indicated that, based on the analysis for the IP3 reactor internals, the response due to FIVs was extremely small and well within the allowable levels based on the high-cycle endurance limit for the materials. Provide a summary of the evaluation regarding the quantity of the response and the FIV analysis with respect to the fluid elastic instability, turbulent flow and vortex shedding and acoustic resonance. Also, provide the calculated vibration level and describe the allowable limit in your acceptance criteria.

Response ME-6:

Flow induced vibrations of pressurized water reactor internals have been studied at Westinghouse for a number of years. The objective of these studies is to assure the structural integrity and reliability of the reactor internals components. These efforts have included in-plant tests, scale model tests, tests in fabricators' shops, bench tests of components, and various analytical investigations. The results of scale model and in-plant tests indicate that the vibrational behavior of 2-, 3-, and 4-loop plants is essentially similar; the results obtained from each of the tests complement one another and make possible a better understanding of the flow induced vibration phenomena.

As described in References 1 and 2, Westinghouse instituted a comprehensive instrumented testing program at the Indian Point Unit 2 plant. The results of this program were used to develop theories and concepts related to reactor internals vibration under various operating conditions. The testing performed at Indian Point 2 included the acquisition of data during hot functional testing. The results of this comprehensive testing program showed that the vibrational response of the reactor internals is small and that adequate margins of safety exist with regard to flow induced vibration.

To address the SPU program at IP3 an evaluation was performed to show that the vibration characteristics of reactor internals does not change significantly and the structural adequacy of the reactor internals in regards to FIV is not impaired, results of this evaluation are given in Table ME-6-1 below.

TABLE ME-6-1

Component	Stress @HFT (psi)		Alt. Stress @SPU (psi)		Allowable Stress (psi)
Core Barrel Flange				a,c	23,700
Girth Weld					23,700
Flexures					23,700
Top Support Bolts					23,700

References:

1. WCAP-7875, "IPP-2 Reactor Internals Vibration Program", October 1972.
2. WCAP-7879, "Four Loop PWR Internals Assurance and Test Program", July 1972.

Question ME-7:

In Table 5.3-2, the stress in the lower joint of the control rod drive mechanism (CRDM) canopy after the SPU will exceed the ASME Code allowable value of $3S_m$. The footnote states that the difference is insignificant. Provide the justification on how this issue was resolved.

Response ME-7:

The exceedance of [ ]^{a,c} psi will produce a Ke factor of [ ]^{a,c}, which did not affect the fatigue usage factor value. Calculations were performed for the SPU conditions which gave a fatigue usage of [ ]^{a,c}.

Question ME-11:

With regard to Section 5.6.1 of the application, provide an evaluation for the effect of FIV on the SG steam dryer, and dryer supports with respect to the fluid-elastic instability, acoustic loads, turbulence and vortex shedding due to the increased steam flow for the power uprate.

Response ME-11:

The type of steam dryer (secondary moisture separator) used by Westinghouse consists of a multi vane assembly. In this assembly the steam/water mixture must pass thru a torturous path that results in water droplets becoming entrain in the small areas built into the vane assembly. These water droplets contact the vane and are then pulled down by gravity to a drain. What makes this work so well is the reduced velocity of the steam as it enters the gaps between the individual vanes that make up the dryer. This is due in a large part as a result of the large surface area associated with the dryer. As a result of this design, FIV of the dryer has never been a concern because:

4) Low fluid velocities associated with the dryer due to large surface areas
5) High stiffness of the assembly due to the torturous path associated with each vane (High stiffness results in higher natural frequencies which results in a reduced potential for FIV).
6) Based on past SG inspections no indications of high flow and or FIV of the separator have been found.

For Indian Point 3, at 1.4% MUR operating conditions, the steam velocity approaching the dryer face is approximately $[3.2]^{a,c}$ ft/sec and the steam density is approximately $[1.85]^{a,c}$ lbm/ft^3. For different pressure and NSSS power, estimates can be made for the equivalent steam velocity. At 4.8% SPU operating conditions at the lowest (resulting in worst case steam velocity) steam pressure, the steam velocity is approximately $[4.6]^{a,c}$ ft/sec and the steam density is approximately $[1.24]^{a,c}$ lbm/ft^3. The steam velocities at both the 1.4% MUR and 4.8% SPU operating conditions are low. Low density and low velocity relate to low dynamic pressure to the dryer and low loading to FIV.

STEAM GENERATOR STRUCTURAL INTEGRITY EVALUATION

Question SG-2:

The conclusions for shop welded plugs in Section 5.6.4 states that "[a]ll primary stresses are satisfied for the weld between the weld plug and the tubesheet cladding," and "[t]he overall maximum primary-plus-secondary stresses for the enveloping transient case of 'loss-of-load' was determined to be acceptable," and "[i]t was determined that the fatigue exemption rules were met, and therefore, fatigue conditions are acceptable."

Question SG-2a:

Provide a table (similar to Table 5.6-2 for the primary and secondary side components) that summarizes the load conditions, stress categories, ASME Code allowables, and all applicable stress- and fatigue-related calculation results that support your conclusions for the shop weld plugs. Show the calculation results which indicate that ASME Code allowables were met.

Response SG-2a:

The requested table is provided as follows.

Table SG-2a-1
Stress Summary for Shop Welded Plugs

Loading Condition	Calculated Maximum Stress Intensity (psi)	ASME Code Limit (psi) (Note 1)
Design	a,c	0.5Sm = 0.5x23,300 = 15,750 psi 0.5(1.5Sm) = 0.5x1.5x23,300 = 23,625 psi
Operating (Normal and Upset Conditions)		0.5(3.0Sm) = 0.5x3.0x23,300 = 34,950 psi
Test		0.5(0.9Sy) = 0.5x0.9x35,000 = 15,750 psi 0.5(1.35Sy) = 0.5x1.35x35,000 = 23,625 psi (3.0Sm) = 3.0x23,300 = 69,900 psi

Note 1: The shop weld plug is welded to the tube end using a full penetration weld. This weld geometry is similar to a corner weld configuration as shown in Figure N-462.3 (2) of the 1965 ASME Code, Section III, Article 4 (Equivalent to Figure NB-3352.3-1, Type 1b of later code years). The ASME Code of Record for the design of the steam generator is the 1965 ASME Code, through the summer 1966 Addenda. The ASME Code, Section III, Article 4 (Section NB of later codes) does not require or specify a factor to be applied to the stress allowable values to reduce the values due to weld quality. It has been Westinghouse's approach to apply a weld quality factor to this weld of the shop weld plug to a tube. This is a conservative approach since the ASME Code is silent on applying a weld quality factor. A weld quality factor of 0.5 is applied. A weld quality factor was not applied to the $[P_L + P_B + Q]_{RANGE}$. The weld was analyzed based on the ASME Code, Section III, Article 4 and all stresses are found acceptable.

Question SG-2b:

Provide the basis and calculation results (if any) for satisfying the ASME Code fatigue exemption requirements.

Response SG-2b:

The response to this question was provided in a table in letter NL-04-145 of November 18, 2004, in Attachments 3 (proprietary) and 4 (non-proprietary) in response to IP2 item Question NL-04-073-SG-3 (Table NL-04-073-SG-3-2 Shop Welded Plug Fatigue Evaluation based on Fatigue Exemption rules of ASME code Section N-474-1.)