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Fred Dacimo
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April 12, 2004

Re: Indian Point Unit 2
Docket No. 50-247
NL-04-039

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

Subject: **Supporting Information for License Amendment Request Regarding Indian Point 2 Stretch Power Uprate (TAC MC 1865)**

Reference:

1) Entergy Letter NL-04-005 to NRC; "Proposed Changes to Technical Specifications: Stretch Power Uprate Increase of Licensed Thermal Power (3.26%)," dated January 29, 2004

2) Nuclear Regulatory Commission, Summary of March 9, 2004, Meeting regarding Stretch Power Uprate License Amendment Application, Indian Point Nuclear Generating Unit No. 2, NRC public meeting with Entergy Nuclear Operations, Inc. dated March 29, 2004

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 2 (IP2). This information is being provided in response to a conference call with the NRC staff on February 18, 2004 and the public meeting (Reference 2) on March 9, 2004. Attachment I contains cross-reference tables as follows:

- Table 1: Cross-Map of WCAP-16157-P Sections to Topical Areas
  This table correlates the NRC review topical areas to the corresponding analysis and evaluation sections in WCAP-16157-P (Enclosure B of Reference 1).

- Table 2: Cross-Map of Proposed Technical Specification Changes to WCAP-16157-P Sections
  This table identifies sections in WCAP-16157-P with safety analyses pertaining to the new Technical Specification allowable values proposed in Reference 1 for the IP2 Reactor Protection System and the Engineered Safety Feature Actuation System.

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- Table 3: Matrix of Affected and Unaffected Systems, Components, and Analyses
  This table identifies whether IP2 systems, components, and analyses were affected or unaffected by the proposed stretch uprate and the reconciliation method used to disposition affected items.

Attachment II provides answers to questions to support review by the plant systems branch as discussed in the February 18 conference call and at the March 9 public meeting. Attachment III provides answers to questions to support reviews by the Reactor Systems Branch and the Electrical and Instrumentation & Controls Branch as discussed at the March 9 public meeting.

As discussed during our presentation on March 9, the process for developing the amendment request included a review of NRC Requests for Additional Information (RAI) on similar amendment requests. Entergy has reviewed several RAIs that have recently been issued for another licensee following our submittal of Reference 1. Additional information pertaining to applicable RAIs is incorporated in the attachments to this letter.

These attachments provide clarifying information to better identify the extent to which systems, components, and analyses are affected by the SPU conditions. The areas where Entergy is specifically requesting NRC approval are the following:

1. Technical Specification changes set forth in Attachment II to Reference 1, and;

2. Accident analysis assumption pertaining to auxiliary feedwater system operation for the Loss-of-Normal Feedwater (LONF) event and the Loss of All AC Power to Station Auxiliaries (LOAC) event. (See WCAP-16157-P, Sections 6.3.1, 6.3.7 and 6.3.8 (Reference 1) and Attachment II of this letter, items 18, 19, and 20)

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 4/12/2004

Sincerely,

Fred R. Dacimo
Vice President, Operations
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cc: next page

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ATTACHMENT I TO NL-04-039

IP2 STRETCH UPRATE LICENSE AMENDMENT REQUEST

TABLES

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas

MATERIALS AND CHEMICAL ENGINEERING	LAR SECTION
Reactor Vessel Material Surveillance Program	5.1 Reactor Vessel
Pressure-Temperature Limits and Upper Shelf Energy	5.1 Reactor Vessel
Pressurized Thermal Shock	5.1 Reactor Vessel
Reactor Internal and Core Support Materials	5.10 RCS Potential Material Degradation Assessment
Reactor Coolant Pressure Boundary Materials	5.0 Nuclear Steam Supply System Components 5.10 RCS Potential Material Degradation Assessment
Leak-Before-Break	5.4.2 Application of LBB Methodology
Protective Coating Systems (Paints) – Organic Materials	Existing requirements for protective coatings are being retained
Effect of Power Uprate on Flow Accelerated Corrosion	10.3 Flow Accelerated Corrosion Program
Steam Generator Tube Inservice Inspection	5.6 Steam Generators
Steam Generator Blowdown System	9.5 Steam Generator Blowdown System
Chemical and Volume Control System - Including Boron Recovery	4.1.2 CVCS
Reactor Water Cleanup System (BWR)	NA

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

MECHANICAL AND CHEMICAL ENGINEERING	LAR SECTION
Pipe Rupture Locations and Associated Dynamic Effects	5.4 Reactor Coolant Loop Piping and Supports 9.9 Piping and Supports
Pressure-Retaining Components and Component Supports	4.1 Nuclear Steam Supply Fluid Systems 5.1 Reactor Vessel 5.3 Control Rod Drive Mechanisms 5.4 Reactor Coolant Loop Piping and Supports 5.7 Pressurizer 5.6 Steam Generators 5.5 Reactor Coolant Pumps and Motors 5.8 Nuclear Steam Supply System Auxiliary Equipment 9.0 BOP Systems 9.9 Piping and Supports
Reactor Pressure Vessel Internals and Core Supports	5.2 Reactor Pressure Vessel System
Safety-Related Valves and Pumps	4.1 Nuclear Steam Supply Fluid Systems 5.8 Nuclear Steam Supply System Auxiliary Equipment 10.2 Generic Letter 89-10 Motor-Operated Valve Program
Seismic and Dynamic Qualification of Mechanical and Electrical Equipment	5.1 Reactor Vessel 5.3 Control Rod Drive Mechanisms 5.4 Reactor Coolant Loop Piping and Supports 5.7 Pressurizer 5.6 Steam Generators 5.5 Reactor Coolant Pumps and Motors 5.8 Nuclear Steam Supply System Auxiliary Equipment 9.0 BOP Systems 10.8 Electrical Equipment Environmental Qualification Program

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

ELECTRICAL ENGINEERING	LAR SECTION
Environmental Qualification of Electrical Equipment	10.8 Electrical Equipment Environmental Qualification Program
Offsite Power System	9.8 Electrical Systems
AC Onsite Power System	9.8 Electrical Systems
DC Onsite Power System	9.8 Electrical Systems
Station Blackout	4.1.3 Residual Heat Removal System 4.1.6 Component Cooling Water System 10.6 Station Blackout

INSTRUMENTATION AND CONTROLS	LAR SECTION
Reactor Trip System	6.1 Initial Condition Uncertainties 6.10 Reactor Trip System/Engineered Safety Feature Actuation System Setpoints
Engineered Safety Features Systems	6.1 Initial Condition Uncertainties 6.10 Reactor Trip System/Engineered Safety Feature Actuation System Setpoints
Safety Shutdown Systems	6.1 Initial Condition Uncertainties 6.10 Reactor Trip System/Engineered Safety Feature Actuation System Setpoints
Control Systems	4.3 Nuclear Steam Supply System Control Systems 9.10 BOP Instrumentation and Controls
Diverse I&C Systems	N/A
General guidance for use of other SRP Sections related to I&C	4.3 Nuclear Steam Supply System Control Systems 9.10 BOP Instrumentation and Controls

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

PLANT SYSTEMS	LAR SECTION
Flood Protection	10.4 Flooding
Equipment and Floor Drainage System	10.4 Flooding and Attach. II Item 1
Circulating Water System	9.7 Circulating Water System and Main Condenser
Internally Generated Missiles (Outside Containment)	8.1 Steam Turbine and Attach. II items 3 and 4
Internally Generated Missiles (Inside Containment)	Attach. II item 5
Turbine Generator	8.1 Steam Turbine
Protection against Postulated Piping Failures in Fluid Systems Outside Containment	9.9 Piping and Supports
Fire Protection Program	10.1 Fire Protection (10CFR50 Appendix R) Program
Pressurizer Relief Tank	4.1.1 Reactor Coolant System
Fission Product Control Systems and Structures	N/A
Main Condenser Evacuation System	9.7 Circulating Water System and Main Condenser
Turbine Gland Sealing System	9.1 Main Steam System
Main Steam Isolation Valve Leakage Control System	N/A
Spent Fuel Pool Area Ventilation System	9.11 Area Ventilation (HVAC)
Auxiliary and Radwaste Area Ventilation System	9.11 Area Ventilation (HVAC)
Turbine Area Ventilation System	9.11 Area Ventilation (HVAC)
ESF Ventilation System	9.11 Area Ventilation (HVAC)
Spent Fuel Pool Cooling and Cleanup System	4.1.7 SFP Cooling System
Station Service Water System	9.6 Essential and Non-Essential Service Water System
Reactor Auxiliary Cooling Water Systems	4.1.6 Component Cooling Water System
Ultimate Heat Sink	9.7 Circulating Water System and Main Condenser
Auxiliary Feedwater System	4.2 NSSS/Balance-of-Plant Interface Systems 6 Safety Analysis 9.12 Auxiliary Feedwater System
Main Steam Supply System	9.1 Main Steam System
Main Condenser	9.7 Circulating Water System and Main Condenser
Turbine Bypass System	9.1 Main Steam System
Condensate and Feedwater System	9.4 Main Feedwater and Condensate System
Gaseous Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Liquid Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Solid Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Emergency Diesel Engine Fuel Oil Storage and Transfer System	See Attachment II item 46
Light Load Handling System (Related to Refueling)	6.11.5 Normal Operation Dose Rates and Shielding 6.11.9 Radiological Consequences Evaluations (Doses) See also Attachment II item 47

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

CONTAINMENTS	LAR SECTION
Dry Containments	6.5 LOCA Containment Integrity 6.6.2 Steamline Break Containment Response Evaluation
Ice Condenser Containments	N/A
Pressure-Suppression Type BWR Containments	N/A
Subcompartment Analysis	6.5 LOCA Containment Integrity
Mass and Energy Release for Postulated LOCA	6.5.1 Long-Term LOCA M&E Releases
Mass and Energy Release for Postulated Secondary System Pipe Ruptures	6.6.1 Main Steamline Break M&E Releases Inside Containment Responses 6.6.3 Main Steamline Break M&E Releases Outside Containment Responses
Combustible Gas Control in Containment	Note 1
Containment Heat Removal	4.1.4 Emergency Core Cooling System (Safety Injection System/Containment Spray System) 6.5 LOCA Containment Integrity 9.11 Area Ventilation (HVAC)
Secondary Containment Functional Design	N/A
Minimum Containment Pressure Analysis for ECCS Performance Capability Studies	6.2.1 Large-Break Loss-of-Coolant Accident

Note: 1 The existing Combustible Gas Control System in containment is discussed in UFSAR Section 6.8. The Passive Autocatalytic Recombiners were approved for use by NRC in License Amendment 200 dated April 27, 1999. The analysis of hydrogen generation supporting that license amendment request was performed at a Reactor Power level of 3216 MWt. Thus there is no effect of the SPU to 3216 MWt on the Combustible Gas Control System.

HABITABILITY, FILTRATION AND VENTILATION	LAR SECTION
Control Room Habitability System	6.11.9 Radiological Consequences Evaluations (Doses) 9.11 Area Ventilation (HVAC)
ESF Atmosphere Cleanup System	9.11 Area Ventilation (HVAC)
Control Room Area Ventilation System	9.11 Area Ventilation (HVAC)
Spent Fuel Pool Area Ventilation System	9.11 Area Ventilation (HVAC)
Auxiliary and Radwaste Area Ventilation System	9.11 Area Ventilation (HVAC)
Turbine Area Ventilation System	9.11 Area Ventilation (HVAC)
ESF Ventilation System	9.11 Area Ventilation (HVAC)

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

REACTOR SYSTEMS	LAR SECTION
Fuel System Design	7.1 Fuel Design Features and Components
Nuclear Design	7.3 Fuel Core Design 7.4 Fuel Rod Design and Performance
Thermal and Hydraulic Design	7.2 Core Thermal-Hydraulic Design
Functional Design of Control Rod Drive System	5.3 Control Rod Drive Mechanisms 5.2.3 RCCA Scram Performance Evaluation
Overpressure Protection during Power Operation	4.1 Nuclear Steam Supply System Fluid Systems 4.3.2 Pressurizer Pressure Control System Component Sizing 5.7 Pressurizer 6.3.6 Loss-of-External Electrical Load
Overpressure Protection during Low Temperature Operation	4.3.3 Overpressure Protection System
Reactor Core Isolation Cooling System (BWR)	N/A
Residual Heat Removal System	4.1.3 Residual Heat Removal System
Emergency Core Cooling System	4.1.4 Emergency Core Cooling System (Safety Injection System/Containment Spray System)
Standby Liquid Control System (BWR)	N/A
Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	6.3.9 Excessive Heat Removal Due to Feedwater System Malfunction 6.3.10 Excessive Load Increase Incident 6.3.11 Rupture of a Steam Pipe
Steam System Piping Failures Inside and Outside Containment	6.3.11 Rupture of a Steam Pipe 6.6.2 Steamline Break Containment Response Evaluation 6.6.4 Main Steamline Break Outside Containment Compartment Response
Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulator Failure (Closed)	6.3.6 Loss-of-External Electrical Load
Loss of Non-emergency AC Power to Station Auxiliaries	6.3.8 LOAC to the Station Auxiliaries
Loss of Normal Feedwater Flow	6.3.7 Loss-of-Normal Feedwater
Feedwater System Pipe Breaks Inside and Outside Containment	Not in licensing basis
Loss of Forced Reactor Coolant Flow including Trip of Pump Motor and Flow Controller Malfunctions	6.3.12 Partial Loss of Reactor Coolant Flow 6.3.13 Complete Loss-of-Reactor-Coolant Flow
Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	6.3.14 Locked Rotor Accident
Uncontrolled Control Rod Assembly Withdrawal from a Sub-critical or Low Power Condition	6.3.2 Uncontrolled RCCA Withdrawal from a Subcritical or Low Power Startup Condition
Uncontrolled Control Rod Assembly Withdrawal at Power	6.3.3 Uncontrolled RCCA Assembly Withdrawal at Power

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

REACTOR SYSTEMS	LAR SECTION
Control Rod Misoperation (System Malfunction or Operator Error)	6.3.4 RCCA Drop/Misoperation
Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate	Table 6.3-1, List of Non-LOCA Events
Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	6.3.5 Chemical and Volume Control System Malfunction
Spectrum of Rod Ejection Accidents	6.3.15 Rupture of a CRDM Housing – RCCA Ejection
Spectrum of Rod Drop Accidents	6.3.4 RCCA Drop/Misoperation
Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that increases Reactor Coolant Inventory	NA
Inadvertent Opening of a Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve	6.2.2 Small Break LOCA
Steam Generator Tube Rupture	6.4 Steam Generator Tube Rupture Transient
Loss of Coolant Accidents Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary	6.2 Loss-of-Coolant Transients
Anticipated Transients Without Scram	6.8 Anticipated Transients Without Scram
New Fuel Storage	Note 2
Spent Fuel Storage	Note 2 See also Attachment III item 3.

Note: 2 Review is applicable if the SPU is requesting approval for new fuel. The Indian Point 2 SPU LAR is not requesting approval of new fuel, thus these categories are not applicable. The analyses and evaluations presented in Section 9 of the IP2 UFSAR will remain valid for the fuel associated with the SPU.

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

SOURCE TERMS AND RADIOLOGICAL CONSEQUENCES ANALYSES	LAR SECTION
Source Terms for Input into Radwaste Management Systems Analyses	6.11.4 Radiation Source Terms
Radiological Consequence Analyses Using Alternative Source Terms	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Main Steamline Failures Outside Containment for a PWR	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Control Rod Ejection Accident	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Control Rod Drop Accident	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment	6..11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Steam Generator Tube Failure	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Main Steamline Failure Outside Containment for a BWR	N/A
Radiological Consequences of a Design Basis Loss of Coolant Accident including Containment Leakage Contribution	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Design Basis Loss of Coolant Accident Leakage from ESF Components Outside Containment	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Design Basis Loss of Coolant Accident Leakage from Main Steam Isolation Valves (BWR)	N/A
Radiological Consequences of Fuel Handling Accidents	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Spent Fuel Cask Drop Accidents	6.11.9 Radiological Consequences Evaluations (Doses)

Table 1 - Cross-Map of WCAP-16157-P Sections to Topical Areas (Cont'd)

HEALTH PHYSICS	LAR SECTION
Radiation Sources	6.11.4 Radiation Source Terms
Radiation Protection Design Features	6.11.5 Normal Operation Dose Rates and Shielding
Operational Radiation Protection Program	6.11.5 Normal Operation Dose Rates and Shielding

HUMAN PERFORMANCE	LAR SECTION
Reactor Operating Training	10.15.2 Effect on Operator Actions and Training
Training for Non-Licensed Plant Staff	10.15.2 Effect on Operator Actions and Training
Operating and Emergency Operating Procedures	6.12 EOPs and EOP Setpoints 10.15.1 Procedures
Human Factors Engineering	10.15 Plant Operations

POWER ASCENSION AND TESTING PLAN	LAR SECTION
Power Ascension and Testing	10.15.4 Startup Testing

RISK EVALUATION	LAR SECTION
Risk Evaluation	10.5 Probabilistic Safety Assessment

Table 2 - Cross-Map of Technical Specification Changes to WCAP-16157-P Analyses		
Proposed TS Change	WCAP-16157 Section	Comments
Tech Spec Table 3.3.1-1 (RPS Instrumentation) Allowable Value changes		
Function 2.a Power range neutron flux (high): Change allowable value from ≤ 112.6% RTP to ≤ 110.6% RTP	6.3.3 6.10	This function provides protection for uncontrolled rod withdrawal at power. To ensure the licensing basis acceptance criteria is met for this event, a lower high neutron flux safety analysis limit (SAL) trip setpoint was modeled which reduced the SAL from 118% RTP to 116% RTP. Sufficient uncertainty margin existed to preclude the need to change the nominal trip setpoint, despite the change in SAL. However, since the allowable value is based on the SAL and the non-tested uncertainties, a revised allowable value was calculated based on the revised SAL.
Function 9 Reactor Coolant Flow – low: Change allowable value from ≥ 88.8% to ≥ 88.7%	6.10	This function provides protection for partial or complete loss of reactor coolant flow and the locked rotor event. The SAL for this function remains at 85%. However, since the allowable value is based on the SAL and the non-tested uncertainties, and since one of the non-tested uncertainties (process measurement accuracy) changed slightly for the SPU, a revised allowable value was calculated.
Function 13 Steam Generator water level – low-low: Change allowable value from ≥ 3.7% to ≥ 3.4%	6.10	This function is one of several functions that can provide protection for loss of normal feedwater. The SAL for this function remains at 0% narrow range level. However, since the allowable value is based on the SAL and the non-tested uncertainties, and since one of the non-tested uncertainties (process measurement accuracy) changed slightly for the SPU, a revised allowable value was calculated.
Function 14 Steam Generator water level – low: Change allowable value from ≥ 3.7% to ≥ 3.4%	6.10	Same as above for Function 13
Function 5, Note 1 Overtemperature ΔT: Change allowable value from 3.3% to 4.9% ΔT span	6.3.1 6.10	Provides DNB protection for non-LOCA transients. The SAL for K1 max is being changed from 1.40 to 1.42 and the SAL for K3 is being changed from 0.00095/psi to 0.00070/psi to increase the channel uncertainty margin. The Overtemperature ΔT settings were analyzed to ensure the core thermal limits are protected (to preclude DNB) for overtemperature conditions and to ensure the RTD temperature measurement range is preserved. Since the allowable value is based on the SAL and the non-tested uncertainties, a revised allowable value was calculated based on the revised SAL.
Function 6, Note 2: Overpower ΔT: Change allowable value from 2.3% to 2.4% ΔT span	6.3.1 6.10	Provides fuel centerline temperature protection for non-LOCA transients. The SAL for K_4 max is being changed from 1.154 to 1.64 to increase the channel uncertainty margin. The Overpower ΔT settings were analyzed to ensure overpower (fuel centerline) conditions and core thermal limits are protected (to precluded DNB). Since the allowable value is based on the SAL and the non-tested uncertainties, a revised allowable value was calculated based on the revised SAL.

Table 2 - Cross-Map of Technical Specification Changes to WCAP-16157-P Analyses		
Proposed TS Change	WCAP-16157 Section	Comments
Table 3.3.2-1 (ESFAS Instrumentation) Allowable Values Changes		
Function 1.f High Steam Flow - Safety Injection, Coincident with T_{avg} – low: Change the allowable value from ≥ 540.75 F to ≥ 540.5 F.	6.3.11 6.10	This function is part of the steamline break (SLB) protection system. To enable more timely steamline isolation/safety injection actuation for the SLB event, a revised low T_{avg} SLB protection logic actuation setpoint of 537°F was assumed. Since the allowable value is based on the SAL and the non-tested uncertainties, a revised allowable value was calculated based on the revised SAL.
Function 1.g High Steam Flow - Safety Injection, Coincident with steamline pressure – low: Change the allowable value from ≥ 425.0 to ≥ 540.3 psig.	6.3.11 6.10	This function is part of the steamline break (SLB) protection system. To enable more timely steamline isolation/safety injection actuation for the SLB event, the low steamline pressure SLB protection logic actuation SAL is being increased from 400 psig to 515.3 psig, in conjunction with an increase in the nominal setpoint from 525 psig to 565.3 psig. Since the allowable value is based on the SAL and the non-tested uncertainties, a revised allowable value was calculated based on the revised SAL.
Functions 1.f, 1.g, 4.d, and 4.e, Note (b) regarding turbine first stage pressure: Change allowable values from 53.7% to 45.9% full steam flow at or below 20% load, and increasing linearly from that value at 20% load to a value revised from 110.8% to 122.0% full steam flow at 100% load, and revised from 110.8% to 122.0% full steam flow above 100% load.	6.3.11 6.10	These functions are changes that enable a more timely actuation of the steamline break (SLB) protection system. Included is a reduction in the high steam flow SLB protection logic actuation SAL setpoint from 74% to 64% steam flow for the low power condition (i.e., < 20 % power). Since the allowable value is based on the SAL and the non-tested uncertainties, a revised low power allowable value was calculated based on the revised SAL. In addition, although the SAL for the high power condition (i.e., 100 % power) remains at 144% steam flow, the full power allowable value was recalculated to reflect the non-tested uncertainties calculated for the SPU conditions, and to maintain the allowable value on the instrument span.
Function 4.d High Steam Flow - Steam Line Isolation, Coincident with T_{avg} – low: Change the allowable value from ≥ 540.75 F to ≥ 540.5 F.	6.3.11 6.10	Same as function 1.f

Table 2 - Cross-Map of Technical Specification Changes to WCAP-16157-P Analyses		
Proposed TS Change	WCAP-16157 Section	Comments
Function 4.e High Steam Flow – Steam Line Isolation, Coincident with Steam Line pressure – low: Change the allowable value from ≥ 425.0 to ≥ 540.3 psig.	6.3.11 6.10	Same as function 1.g
Function 5.b Feedwater Isolation, SG Water Level – high-high: Change allowable value from ≤ 77.7% to ≤ 88.3%.	6.3.1 6.10	This function provides protection for overfilling the SGs. The SAL for this function is being changed from 80% to 90% narrow range level due to potential increases in uncertainty associated with SG level process uncertainties. Since the allowable value is based on the SAL and the non-tested uncertainties, a revised allowable value was calculated based on the revised SAL.
Function 6.b Auxiliary Feedwater, SG Water Level – low-low: Change allowable value from ≥ 3.7% to ≥ 3.4%.	6.10	Same as functions 13 and 14 for the RPS Instrumentation

TABLE 3 - IP2 SPU Affected / Unaffected Matrix for Attachment III to the LAR			
Section 4: NSSS Systems			
LAR Section and System	**Affected Or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
4.1.1 RCS	Affected	Evaluation and Analysis	No
4.1.2 CVCS	Unaffected	Evaluation	No
4.1.3 RHR	Affected	Evaluation and Analysis	No
4.1.4 ECCS (SIS and CSS)	Affected	Analysis	No
4.1.5 PSS	Unaffected	Evaluation and Analysis	No
4.1.6 CCWS	Affected	Evaluation and Analysis	No
4.1.7 SFPCS	Affected	Analysis	No
4.2.1 MSS	Affected	Analysis	No
4.2.2 Steam Dump	Affected	Analysis	No
4.2.3 C&FS	Affected	Evaluation and Analysis	No
4.2.4 AFWS	Affected	Analysis	No
4.2.5 SG Blowdown	Unaffected	Evaluation	No
4.3.1 NSSS Stability & Operability	Affected	Analysis	No
4.3.2 Pressurizer Pressure Control	Affected	Analysis	No
4.3.3 OPS	Affected	Evaluation	No
4.3.4 I&C Systems	Affected	Evaluation	No
Section 5: NSSS Components			
LAR Section and Component	**Affected Or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
5.1.1 RV Structural	Affected	Evaluation and Analysis	No
5.1.2 RV Integrity	Affected	Analysis	No
5.2.2 RV/RVI System T&H	Affected	Analysis	No
5.2.3 RCCA Scram Performance	Affected	Analysis	No
5.2.4 RV/RVI Mechanical	Affected	Analysis	No
5.2.5 RVI Components	Unaffected	Evaluation	No
5.2.6 BMI Guide Tubes	Affected	Analysis	No
5.3 CRDMs	Unaffected	Evaluation	No
5.4 RCL Piping/Supports	Affected	Analysis	No
5.5 RCP Pumps / Motors	Unaffected	Evaluation	No
5.6.1 SG T&H	Affected	Analysis	No
5.6.2 SG Structural	Affected	Analysis	No
5.6.3 Primary-to-Secondary ΔP	Affected	Analysis	No
5.6.4 SG Repair Hardware	Affected	Analysis	No
5.6.5 Reg. Guide 1.121	Affected	Analysis	No
5.6.6 SG Tube Vibration / Wear	Affected	Analysis	No
5.6.7 SG Tube Integrity	Unaffected	Evaluation	No
5.7 Pressurizer	Affected	Analysis	No
5.8 NSSS Auxiliary Equip.	Unaffected	Evaluation	No
5.9 NSSS Fracture Integrity	Affected	Analysis	No
5.10 NSSS Material Degradation	Unaffected	Evaluation	No(9)

TABLE 3 - IP2 SPU Affected / Unaffected Matrix for Attachment III to the LAR			
Section 6: UFSAR Chapter 14 Safety Analyses			
LAR Section and Accident Analysis	**Affected Or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
6.1 Initial Condition Uncertainties	Affected	Analysis	No
6.2 LOCA Analyses	Affected	Evaluations and Analysis	No
6.3.2 Rod Withdrawal at Subcritical	Affected	Evaluations and Analysis	No
6.3.3 Rod Withdrawal at Power	Affected	Analysis	No
6.3.4 RCCA Drop	Affected	Analysis	No
6.3.5 CVCS Malfunction (Boron Dilution)	Affected	Analysis	No
6.3.6 Loss of Load	Affected	Analysis	No
6.3.7 Loss of Normal Feedwater	Affected	Analysis	No(8)
6.3.8 Loss of AC Power	Affected	Analysis	No(8)
6.3.9 Feedwater Malfunction	Affected	Analysis	No
6.3.10 Excessive Load Increase	Affected	Evaluation and Analysis	No
6.3.11 Main Steamline Break	Affected	Analysis	No
6.3.12 Partial Loss of Flow	Affected	Analysis	No
6.3.13 Complete Loss of Flow	Affected	Analysis	No
6.3.14 Locked Rotor	Affected	Analysis	No
6.3.15 Rod Ejection	Affected	Analysis	No
6.4 SG Tube Rupture	Affected	Analysis	No
6.5 LOCA Containment Integrity	Affected	Analysis	No
6.6.2 MSLB Containment Integrity	Affected	Analysis	No
6.6.4 MSLB Outside Containment Compartment Response	Affected	Analysis	No
6.7 LOCA Forces	Affected	Analysis	No
6.8 ATWS	Affected	Evaluation and Analysis	No
6.9 Natural Circulation Cooldown	Affected	Analysis	No
6.10 RPS/ESFAS Setpoints	Affected	Analysis	No
6.11 Radiological Dose	Affected	Analysis	No
6.12 EOPs and Setpoints	Affected	Analysis	No
Section 7: Fuel and Core Analyses			
LAR Section and Fuel / Core Analysis	**Affected Or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
7.1 Fuel Design Features and Components (Mechanical)	Affected	Analysis	No
7.2 Core T&H	Affected	Analysis	No
7.3 Fuel Core Design	Affected	Analysis	No(1)
7.4 Fuel Rod Design and Performance	Affected	Analysis	No
7.5 Neutron Fluence	Affected	Analysis	No
7.6 Reactor Internals Heat Generation Rate for RVI	Affected	Analysis	No

TABLE 3 - IP2 SPU Affected / Unaffected Matrix for Attachment III to the LAR			
Section 8: Turbine Island Analysis			
LAR Section and Analysis	**Affected Or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
8.1 Steam Turbine	Affected	Evaluations and Analysis	No[2, 3]
8.2 Heat Balances	Affected	Analysis	No[4]
Section 9: BOP Systems and Components			
LAR Section and System or Component	**Affected or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
9.1 Main Steam System	Affected	Analysis/Evaluation	No[3]
9.2 Extraction Steam System	Affected	Analysis/Evaluation	No[3]
9.3 Heater Drain Systems	Affected	Analysis/Evaluation	No[3]
9.4 Main Feedwater and Condensate System	Affected	Analysis/Evaluation	No[3]
9.5 Steam Generator Blowdown	Unaffected	Evaluation	No[3]
9.6 Essential and Non-Essential Service Water	Affected	Analysis/Evaluation	No[3]
9.7 Circulating Water Systems and Main Condensate	Affected	Analysis/Evaluation	No[3]
9.8 Electrical Systems	Unaffected	Evaluation	No[3]
9.9 Piping and Supports	Affected	Analysis/Evaluation	No[5]
9.10 BOP Instruments and Control	Unaffected	Evaluation	No[7]
9.11 Area Ventilation (HVAC)	Unaffected	Evaluation	No
9.12 Auxiliary Feedwater System	Affected	Analysis/Evaluation	No[6]
9.13 Structural Analysis (FHB/AFB)	Affected	Analysis/Evaluation	No[3]

TABLE 3 - IP2 SPU Affected / Unaffected Matrix for Attachment III to the LAR			
Section 10: Generic Issues and Programs			
LAR Section and Issue or Program	**Affected Or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
10.1 Fire Protection (App. R) Program	Unaffected	Evaluation	No(6)
10.2 GL 89-10 MOV Program	Affected	Analysis/Evaluation	No
10.3 Flow Accelerated Corrosion (FAC) Program	Affected	Analysis/Evaluation	No
10.4 Flooding	Unaffected	Evaluation	No
10.5 Probabilistic Safety Assessment	Affected	Analysis/Evaluation	No
10.6 Station Blackout	Unaffected	Evaluation	No
10.7 In-Service Inspection, Testing (ISI and IST)	Unaffected	Evaluation	No
10.8 Electrical Equipment / EQ (Inside & Outside Cont.)	Affected	Analysis/Evaluation	No
10.9 Chemistry Program	Unaffected	Evaluation	No
10.10 GL 95-07	Unaffected	Evaluation	No(3)
10.11 GL 96-06	Unaffected	Evaluation	No(3)
10.12 GL 89-13	Unaffected	Evaluation	No
10.13 Plant Simulator	Affected	Analysis/Evaluation	No
10.14 Containment Leak Rate Testing	Unaffected	Evaluation	No(3)
10.15 Plant Operations	Affected	Analysis/Evaluation	No
Section 11: Environmental Impacts			
LAR Section and Permit Basis	**Affected Or Unaffected ***	**Method of SPU Reconciliation** (Revised AOR or Evaluated Effect on AOR)	**Change to Current Design or Licensing Basis Acceptance Criteria**
11 Environmental Impacts	Unaffected	Evaluation	No

*According to the NRC Guidance for Margin Uncertainty Recapture power uprates in RIS 2002-03:

Unaffected – Unaffected systems, components, or safety analyses are those having current design and licensing bases analyses and calculations that bound the potential effects of the SPU.

Affected – Affected systems, components, or safety analyses are those having current design and licensing bases analyses and calculations that do not bound the potential effects of the SPU.

NOTES

(1) Core designs are checked for each reload cycle to ensure that design bases conditions are bounded.
(2) Confirmation that the existing Turbine Missile analysis remains valid
(3) The original licensing basis acceptance criteria for the BOP systems and components were not detailed. The criteria required that the systems function to produce power and provide reliable operation with minimal transients or trips. For the SPU, these systems were compared to industry standards and criteria to determine acceptability.
(4) There are no acceptance criteria for the Heat Balance per se. The heat balance results are the inputs used for BOP systems and components evaluations and analyses.
(5) BOP piping and supports were evaluated based on change factors.
(6) The Licensing Basis Acceptance Criteria for this system are the acceptance criteria for the operational or safety analyses for which operation of this system or component is assumed.

(7) Evaluation was based on revised Heat Balance parameters and applicable system analysis compared to instrument ranges.
(8) Analysis input assumption changed to credit 10 minute operator action to provide additional AFW flow.
(9) Materials requirements and evaluations continue to be applicable. Technique for evaluation of I-600 susceptibility was not previously applied to IP2

ATTACHMENT II TO NL-04-039

IP2 STRETCH UPRATE LICENSE AMENDMENT REQUEST.

ANSWERS TO QUESTIONS REGARDING

REVIEW BY PLANT SYSTEMS BRANCH

PER CONFERENCE CALL OF 2/18/2004

AND DISCUSSIONS AT THE MARCH 9 PUBLIC MEETING

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

Flood Protection

1 Flooding evaluation does not consider flooding associated with HELB (Section 10.4)

For the SPU, there is no change in the size of tanks or in the amount of fluid in tanks that could lead to flooding from failure of those tanks. The limiting system for flooding effects is the Circulating water system. Performance of the RHR pumps located at Elevation 15' of the Primary Auxiliary Building (PAB) would be affected by flooding only if water level reached Elevation 19'. Flooding to this elevation is precluded by the design of the door to the transformer yard. The flowrates of non-seismic Class 1 potential sources of flooding in the PAB (e.g., Sampling System, portions of the CVCS System, and the Primary Water Makeup System) are not affected by the SPU.

The IP2 licensing basis for flooding is documented in the NRC Safety Evaluation Report, "Susceptibility of Safety-Related Systems to Flooding from Failure of Non-Category I Systems for Indian Point Unit 2," 12/18/1980. It concludes that IP2 can be safely shut down in event of flooding outside containment from a non-seismic component or pipe.

As indicated in the SPU Licensing Report Section 9.9.5, since changes to operating temperatures, pressures, and flow rates for applicable high and moderate energy piping systems are sufficiently small, and there are no new or revised pipe break locations, the existing design basis for pipe break considerations remains acceptable for SPU conditions.

The break locations for the circulating water lines are not affected since the pressures, temperatures and flows are only minimally affected and the physical line arrangements (terminal ends, branch connections, etc.) have not changed. These inputs are not affected and are bounded by the existing evaluation. In addition, the maximum flood levels in all compartments, except the basement levels, are controlled by physical plant features such as doors and curb plates. Therefore, the submergence levels in these areas are not affected by the SPU.

The increase in Feedwater System flow under SPU conditions could result in an increase in flooding in the Auxiliary Feedwater Pump Room due to a postulated HELB in this system. However, current provisions (door design) are in place for assuring that flooding from failure of a feedwater line located adjacent to the Auxiliary Feedwater Pump Room will not affect safety-related equipment in this room.

In summary, the effect of the proposed SPU on the existing flooding analysis has been evaluated. It has been determined that the flooding levels for the equipment at the SPU power level remain unchanged. Any other equipment that was not previously flooded would not be adversely affected by the SPU. Also, the effect of the proposed SPU on internal flooding and submergence levels remains bounded by the existing analysis since the operating conditions (pressures and temperatures) will not change as a result of the SPU, and the volumes of inventory sources that can cause flooding have not increased.

Circulating Water System

2 Describe the reduction in the margin to turbine trip due to reduced circulating water flow margin at SPU conditions and the effect on plant operations. (Section 9.7.5)

The maximum pressure rise in the main condenser results from operation of the main steam dump following a 50% load rejection at the turbine while operating at the SPU power level. This abnormal operating condition maximizes the incoming steam flow and heat load to the condenser.

The SPU evaluation assumes the existing circulating water pumps are not modified and continue to operate at design flow (i.e., 140,000 gpm). A conservative circulating water inlet temperature of 95°F was assumed in the analysis. Using condenser manufacturer's predicted condenser performance curves and a cleanliness factor of 85%, the analysis predicts a resulting condenser pressure of approximately 4.42 inch HgA. This value is slightly below the condenser low pressure alarm setpoint of 5 inch HgA, but has ample margin to the turbine trip setpoint of 8-12 inch HgA.

Internally Generated Missiles (Outside Containment)

3 Discuss in detail how existing criteria capabilities and commitments to prevent the turbine from overspeeding will continue to be satisfied following SPU. (Section 8.1)

The Indian Point 2 Main Turbine consists of a double flow HP turbine and three double flow LP turbines.

The three double flow BB81R LP turbines use a fully integral rotor design. Four failure mechanisms are evaluated; destructive overspeed bursting, high cycle fatigue, low cycle fatigue, and stress corrosion. Of these four mechanisms, stress corrosion is the dominant mechanism for determining the potential for missile generation. Analysis show that the probability of an LP rotor burst by this mechanism does not exceed 10^{-5} even after thirty years of running time. Therefore, it is concluded that these rotors are acceptable to operate at the SPU plant conditions.

The BB96 HP turbine retrofit for Indian Point unit 2 was evaluated for the likelihood of missile generation due to HP rotor burst. The study evaluated the likelihood of missile generation resulting from a burst of a fully integral nuclear high-pressure rotor. Three potential failure mechanisms were considered:

1) Ductile burst due to overspeed.
2) Fracture resulting from high cycle fatigue cracking.
3) Fracture resulting from low cycle fatigue cracking.

A ductile failure analysis showed that a ductile burst will not occur until the speed of the rotor is increased to greater than 240% of rated speed; this is well beyond the design overspeed. A fatigue evaluation showed that the minimum safety factor for the newly designed BB96 HP rotor is two times the safety factor of the original rotor at the limiting location. Since there is no history of high cycle fatigue issues with the existing high pressure turbines, the risk of missile generation from this mechanism is negligible. In the case of low cycle fatigue, the failure mechanism is brittle fracture. A calculation of cyclic life assuming a threshold internal flaw at the highest stressed section based on UT inspection sensitivity showed that the rotor low cycle fatigue life is greater than 10,000 start cycles. Based on the results of this study, there is not a significant likelihood of missile generation for the BB96 HP retrofit.

4 Describe the affect of the power uprate on the IP2 outside containment missile analysis.

SPU changes to operating temperatures, pressures and flow rates for applicable high and moderate energy piping systems are within acceptable limits and there are no new or revised pipe break locations. Thus, existing design basis for pipe break, jet impingement, missile generation and pipe whip considerations remain acceptable for the SPU conditions.

All other rotating equipment remains within its design criteria and therefore, there is no change in the missile analysis or in the protection provisions as a result of the SPU.

Internally Generated Missiles (Inside Containment)

5 Describe the affect of the power uprate on the IP2 inside containment missile analysis.

SPU changes to operating temperatures, pressures and flow rates for applicable high and moderate energy piping systems are within acceptable limits and there are no new or revised pipe break locations. Thus, existing design basis for pipe break, jet impingement, missile generation and pipe whip considerations remain applicable for the SPU conditions.

All other rotating equipment remains within its design criteria and therefore, there is no change in the missile analysis or in the protection provisions as a result of the SPU.

Based on the insignificant changes in system pressures and component overspeed conditions during plant operation and anticipated operational occurrences as a result of the IP2 SPU, systems, structures and components important to safety will continue to be protected from internally generated missiles following implementation of the SPU.

Turbine Generator

6 Describe the affect of the power uprate on the Turbine overspeed trip settings, including how the turbine overspeed equipment meets overspeed protection requirements for the new high pressure turbine.

The construction of Indian Point 2 predates the use of Intercept valves in nuclear plants, therefore, it uses a low pressure steam dump system for overspeed protection. At the time the low pressure steam dump system was qualified, the Indian Point Unit 2 rating was 1021 MWe and the WR^2 was 885,477,900 lb-in^2. The current WR^2 of Indian Point #2 with BB96-(3) BB81R and the GE Generator is 1,143,200,000 lb-in^2, which is approximately 30% larger than the number that was used to qualify the LP dump system originally. A higher WR^2 requires more steam to spin up the turbine to higher speeds and is therefore conservative with respect to the capability of the low pressure steam dump system to provide overspeed protection. Based on the SPU, the required WR^2 would have to be greater than 946,636,997 lb-in^2. The new HP rotor will be approximately 20% heavier than the original HP rotor. Therefore, this will increase the WR^2 approximately 1% further and the LP dump system will remain acceptable at the SPU conditions.

Pressurizer Relief Tank

7 **The text in Section 4.1.1 does not clearly state that the design criterion of being able to quench 110% of the pressurizer steam volume is met or whether the minimum or maximum PRT levels are required to change. Further, discuss the effects of SPU on the stress analysis for the PRT.**

The PRT design criteria continue to be met for SPU.

For the SPU, there is no change in the pressurizer safety valves or power operated relief valves, the discharge piping from these valves or the PRT and its features. The assumed initial temperature of the PRT water (130°F) is unchanged from current design consideration which was evaluated for the 1.4-percent MUR uprate.

The pressurizer relief tank (PRT) is designed to accept and quench the design basis discharge from the pressurizer steam space. The PRT is sized to condense and cool a discharge of steam equivalent to 110 percent of the full-power pressurizer steam volume. The amount of energy absorbed by the PRT is related to the volume and pressure of the steam discharged. As indicated in Table 2.1-2, RCS pressure has not changed for the SPU conditions. However, pressurizer level has changed for the SPU conditions with the level increasing, thereby reducing the pressurizer steam volume.

The loss of load (LOL) transient is the design basis transient for the PRT. The original PRT sizing basis was to quench 110% of the full power steam mass associated with the original LOL sizing analysis ('Condition 1' type transient). For purposes of the SPU, the integrated steam release mass for LOL (see WCAP-16157-P Section 6.3.6) is compared to the mass of steam for the sizing basis for the PRT. Since the Chapter 14 LOL transient criteria is to prevent the pressurizer from going solid (thus preventing water relief through the pressurizer safety valves), the 'design/sizing' basis transient bounds the SPU conditions.

The loss-of-load transient associated with the design PRT steam discharge from the pressurizer was reevaluated for the SPU. The pressurizer steam released as a result of this analysis remains bounded by the PRT design conditions described above, including the effects of the maximum PRT temperature of 130°F. Therefore, the PRT is acceptable for the SPU conditions, including the maximum ambient containment temperature to 130°F.

Changes are not required for the PRT minimum and maximum levels. The text in section 4.1.1 of the LAR states, "The pressurizer steam released as a result of this analysis remains bounded by the PRT design conditions described above, including the effects of the maximum PRT temperature of 130°F. Therefore, the PRT is acceptable for the SPU conditions, including the maximum ambient containment temperature to 130°F." This means that the criterion of being able to quench 110% of the pressurizer steam volume is satisfied.

Since the previous evaluation concluded that the PRT met requirements for operation at 130°F ambient containment temperature, there is no effect on the structural analysis for the PRT. Evaluation of the structural aspects of the NSSS auxiliary equipment is provided in Section 5.8.

Based on the information provided in WCAP-16157-P Sections 4.1.1, 5.8 and 6.3.6 as discussed above, the PRT meets its design criteria and will function effectively for SPU conditions.

Spent Fuel Pool Cooling and Cleanup System

8 Explain how the discussion in Section 4.1.7 demonstrates that the licensing requirements for normal operation are met for the IP2 SPU. Have the assumptions used in developing this analysis method used appropriate design basis requirements and assumptions?

The discussion in Section 4.1.7 addresses the limiting cases for fuel offload with the maximum number of assemblies in the SFP and all of those assemblies having operated at 3216 MWt. The current basis for fuel offload at IP2 is to perform an offload-specific evaluation to determine how much supplemental cooling (if any) is required for the offload. This process is controlled by administrative procedures. In addition to the limiting cases for offload, evaluations were performed for normal operation of the SFP. The results of the normal operation evaluation are provided below:

Normal Operation Spent Fuel Pit Cooling System Performance

The SPU Program affects the SFPCS performance since core power, and therefore the decay heat of the fuel assemblies increases. The SFPCS performance calculation supports the SPU core power of 3216 MWt. The analysis was performed to confirm that the SFPCS and CCWS continue to meet their design basis functional requirements and performance criteria for plant cooldown at the SPU power conditions.

The following assumptions were applied to the SFPCS performance analysis:

- The SFPCS and CCW heat exchanger data assumes 5-percent tube plugging.
- All SFP fuel was assumed to have operated at the SPU reactor power of 3216 MWt to provide a conservative bounding basis for the SFP decay heat load.
- Decay heat curves were based on 24-month fuel cycles.
- The analysis evaluated the capability of the SFPCS and the CCWS to cool the SFP based on SW temperatures of 70 and 95°F.

The SFP maximum normal heat load is 17.7 MBTU/hr. This is based on 20 days elapsed time since the previous shutdown with the maximum number of fuel assemblies in the SFP while still having core offload capacity. With the SFP at 140°F, the SFP heat exchanger with 5 percent tube plugging, and 70°F SW, the SFP heat exchanger will remove 22.6 MBTU/hr. With the SFP at 180°F, the SFP heat exchanger with 5 percent tube plugging, and 95°F SW, the SFP heat exchanger will remove 28.4 MBTU/hr. Therefore, under these conditions the SFPCS has excess capacity.

Station Service Water System

9 Please provide further discussion to demonstrate that the essential service water performance will be acceptable at SPU conditions. (Section 9.6.5)

The stretch power uprate (SPU) will increase the heat rejection to the service water system(SWS). For the SPU evaluation, the existing SWS hydraulic analysis was modified to incorporate the requirements of SPU operation and evaluate flow adequacy to system components and SWS pump capacity and head. The analysis included evaluation of the system heat load removal capability, effects of higher outlet temperatures, and design pressure and temperature of system piping and components and developed system stress analysis and environmental conditions. The hydraulic analysis included worst case conditions assumptions of low river water level, design inlet temperature (95°F), 7%, degraded pump curves and atmospheric vents where applicable.

Analyses verified that the SPU does not affect the flow requirements for any of the equipment fed by the essential SWS header. Some turbine plant equipment fed by the non-essential SWS header required increases in flow including the isolated phase bus duct coolers (current flow of 16 gpm to SPU flow of 40 gpm per cooler), the hydrogen coolers (current flow of 770 gpm to SPU flow of 779 gpm per cooler) , the conventional plant closed cooling heat exchangers (current flow of 300 gpm to SPU flow of 350 gpm per cooler) and the main turbine lube oil coolers(current flow of 1600 gpm to SPU flow of 1680 gpm per cooler).

Outlet service water temperatures were confirmed to be within the system and equipment design specifications, piping design system stress analysis, and plant environmental limits.

SWS pump operation at SPU flow conditions is within the acceptable margins of pump design for all applicable operating modes.

The SWS remains capable of performing its heat removal functions (safety and non-safety) specified for each component for all applicable operating modes.

The SWS piping and components design pressure and temperature bound the SPU pressure and temperature conditions. The existing SWS pipe stress conditions bound SPU conditions and outlet SWS conditions are bounded by existing plant environmental conditions.

Adequate SWS and equipment performance was verified under SPU conditions, including pump NPSH requirements and strainer backwash capability. Increased heat loads from the equipment were found to be bounded by the original equipment and system designs. The increased flow requirements were verified to be within the SWS pump capability. The SWS remains capable of providing the required flow rate for each of its design functions (safety and non-safety) under SPU operating conditions.

10 Evaluation of Generic Letter 96-06 does not include two phase flow and why water hammer does not occur. How does peak containment temperature change? How does this affect vapor volume? If a large margin exists, providing a qualitative evaluation is ok; if not be more specific. (Section 10.11)

As discussed in Section 10.11 of the SPU Licensing Report, the effect of the SPU on GL 96-06 waterhammer issues was evaluated. It was concluded that the column closure waterhammer and the trapping and condensing of steam (steam bubble or void collapse) waterhammer will not be significantly affected by the small (less than 3%) increase in Containment accident peak temperature under SPU conditions. That is, the velocity (critical parameter) of column closure and the volume (critical parameter) of steam bubble formation are not significantly changed by the small increase in Containment ambient temperature.

The service water discharge piping from the containment fan cooler units (CFCUs) are susceptible to two-phase flow conditions during a design basis accident. An evaluation of the studies performed in response to GL 96-06 was completed. The evaluation showed that there was significant margin and that there was no effect on the results of the existing analysis for the susceptibility to two-phase flow conditions during a design basis accident.

Reactor Auxiliary Cooling Water Systems

11 Explain why the reactor vessel support pads are not affected by stretch power conditions.

The discussion of the effect of the SPU on the structural capability of the Reactor Vessel supports is provided in Section 5.4.3.

As noted in Section 2, the NSSS at-power parameters (T_{hot} and T_{cold}) both hot and cold leg temperatures go down at full power and the no-load T_{avg} remains unchanged. The major heat load to the CCWS from the RV support blocks is from the RCS pipe to the support block. Therefore the SPU effect on the need for cooling of the RV support pads would be reduced for at-power operations and unchanged for the cooldown evaluation. Section 4.1.6 states, "Of the CCWS heat loads discussed above, the SFP heat exchanger is the only heat load with a potential to affect the CCWS during normal plant operation."

12 The normal and Appendix R plant cooldown evaluations in Section 4.1.6, do not provide a discussion of additional time that may be required to perform cooldown and do not clearly state whether all applicable criteria and commitments are satisfied.

The discussion in Section 4.1.6 states that, during normal power operation, only the heat loads from the Spent Fuel Pit are affected by the SPU. The specific cooldown results in terms of the time required to complete the cooldown are provided in Section 4.1.3. The discussion in Section 4.1.3 indicates that the Normal cooldown can be completed in 48 hours and the Appendix R cooldown can be completed in less than 72 hours. There is no time limit for normal cooldown and the time limit criterion for the Appendix R cooldown is 72 hours. The performance of the CCW system, assuming the limiting temperatures and the system flow capabilities, meets the requirements in the IP2 licensing documents. See Table 4.1-1 for the cooldown times.

All other applicable criteria and commitments for normal and Appendix R cooldowns in the UFSAR are met. See UFSAR Section 9.3.

Ultimate Heat Sink

13 The effect of the SPU on the Service Water System is discussed in Section 9.6. How does the EPU affect the Ultimate Heat Sink and what criteria are used in that evaluation?

The Ultimate Heat Sink (UHS) for Indian Point Unit 2 is the Hudson River. The Circulating Water System (CWS) (Refer to Section 9.7) and Essential and Non-essential Service Water System (SWS) (Refer to Section 9.6) take cooling water from and discharge waste heat to the UHS. The analyses completed for these systems are based on the most conservative SPU heat balances that include a 0.5% margin.

The CWS is a non-safety related once-through system that uses six (6) CWS pumps to supply water from the Hudson River, circulates it through the main condenser to condense the exhaust steam from the main turbine and other steam/water drains, and returns heated water back to the Hudson River.

Plant operation at the SPU conditions will increase the exhaust steam flow and duty of the main condenser and, therefore, increase the heat load rejected by the CWS to the Hudson River. The existing CW pumps were not modified for SPU and continue to operate at the same flow rates.

Since the CW inlet temperatures from the Hudson River were not affected by the SPU, the CWS discharge temperature to the Hudson River will increase, but is still within the original discharge permit limits.

The SWS is a safety-related system that provides cooling water from the Hudson River to essential (loads that would require cooling water immediately after a loss of power or an accident) and non-essential (loads that do not require cooling water immediately after a loss of power or an accident) components on both the nuclear and conventional sides of the plant.

Essential SWS loads include:

- Containment Recirculation Fan Cooling Coils
- Containment Recirculation Fan Motor Cooling Coils
- Instrument Air Cooling Water Heat Exchangers
- Diesel Generator Lube Oil Coolers and Jacket Water Coolers
- Cooling for Radiation Monitors

Non-essential SWS loads include:

- Component Cooling Water Heat Exchangers
- Feedwater Pump & Turbine Oil Coolers
- Hydrogen Coolers
- Stator Water Coolers
- Isolated Phase Bus Heat Exchangers
- Conventional Closed Cooling Water Heat Exchangers
- Circulating Water Pump Shaft Seal and Bearing Cooling
- Traveling Screens Wash

The SWS removes waste heat from the equipment for all plant operating modes and rejects the waste heat to the Hudson River through a discharge canal. One set of three (3) pumps provides water to the essential header and the other set of three (3) pumps supplies the non-essential header.

Plant operation at the SPU conditions will increase the heat rejection to the SWS. Adequate SWS and equipment performance (safety and non-safety) was verified under SPU conditions, including pump NPSH requirements, system flashing, strainer backwash capability, etc. SWS analyses were completed with worse case assumptions of low water level, design inlet temperature, degraded pumps curves and atmospheric vents, where applicable. Increased heat loads from the equipment were found to be bounded by the original equipment and system design with additional service water flow required to some components. The increased flow requirements were verified to be within the SWS capability. Outlet service water temperatures were confirmed to be within the system and equipment design specifications, piping design system stress analysis, and plant environmental limits.

As described in Section 11, the environmental issues associated with the issuance of an operating license for Indian Point Unit 2 (IP2) were originally evaluated in the IP2 Final Environmental Statement (FES) (Volume 1, page I-1 Section I) and addressed plant operation up to a maximum calculated thermal power of 3216 MWt. The Atomic Energy Commission (AEC), predecessor of the Nuclear Regulatory Commission (NRC), approved the FES in September 1972. In addition to the FES, the Indian Point State Pollutant Discharge Elimination System (SPDES) restrictions on discharge temperatures and discharge flow rates for the station were evaluated along with the flow limits set forth in IP2 Consent Order. Historic river temperature data (taken from 1993 to the present) was used in the SPU analyses. Increased heat rejection to the CWS and SWS at SPU conditions is expected to result in a nominal calculated increase in discharge temperature to the river. This temperature increase falls within the applicable SPDES permit thermal limits for Indian Point.

Auxiliary Feedwater System

Entergy is requesting explicit approval of credit for additional AFW flow at 10 minutes as assumed in the Loss of Normal Feedwater analysis discussed in Section 6.3.7 and the LOAC to the Station Auxiliaries analysis discussed in Section 6.3.8. The AFW System is safety-related. It is required for mitigation of postulated accidents and transients. The design basis for IP2 is hot shutdown. The design basis transients and accidents are listed in Section 9.12 and are discussed in detail in Section 6. Station Blackout is discussed in Section 10.6.

For the SPU, there is no change in the AFW System valves, piping, pumps or automatic actuation signals (see Section 9.12).

14 In Section 4.2.4, the discussion of Auxiliary Feedwater (AFW) interface criteria indicates that evaluations of Section 6 show acceptable results. This discussion is not inclusive of all criteria for the AFW system.

The Westinghouse sizing criteria for the NSSS/BOP interface were originally established to provide guidelines to the BOP designer to ensure that the BOP design would be compatible with the NSSS. Following completion of the BOP designs for each plant, the BOP design parameters and capabilities were then used in the accident and transient analyses to demonstrate that the entire plant design had sufficient capability to accommodate accidents and transients that were postulated. Section 4.2 addresses the original sizing criteria for NSSS/BOP interface that were established to ensure that the BOP was designed with sufficient capability to support operation of the NSSS. Section 4.2.4.1 discusses the design basis requirement (24 hours at hot standby (which bounds SBO AFW inventory requirements)) for CST inventory. The licensing basis acceptance criteria are the accident and transient analyses acceptance criteria. These analyses are discussed in Section 6 and show that the acceptance criteria are met. The summary of the AFWS requirements is provided in Section 9.12 Auxiliary Feedwater System. Additional discussion is provided in item 21.

15 Do previous analyses bound SPU conditions for all design and licensing basis considerations including commitments that have been made?

With the exception of the operator action assumption to provide additional AFW flow at 10 minutes (see Section 6.3.7 and 6.3.8), the SPU conditions have been reanalyzed and meet licensing basis criteria.

16 **What is the basis for the tech spec requirements of 360,000 gal in the CST, and is it affected by the SPU? Explain how the secondary water inventory requirements are met for steam generator tube rupture analysis provided in sec 6.4.1.2. Explain how secondary inventory requirements are met for the table in 6.6-19 analysis. Are there other commitments that need to be considered? (Section 4.2.4.1)**

The design basis for IP2 is hot shutdown. The design basis for the CST volume is the CST inventory required to maintain the plant at hot shutdown for 24 hours following a reactor trip. Since the duration of the SBO event is less than 24 hours, it is bounded by maintaining hot shutdown for 24 hours. This is assured by the TS requirement of a minimum CST inventory of 360,000 gallons. The analysis of Section 4.2.4.1 demonstrates that SPU would require an increase from 284,000 to 291,381 gallons to satisfy the design basis requirement. Thus, considering the unavailable volume and other margins for the CST, the design basis requirement remains satisfied by the existing TS CST volume of 360,000 gallons.

The auxiliary feedwater pumps can draw from an alternative supply of water to provide for long-term cooling. This alternative supply is from the 1.5 million gallon city water storage tank. This supply is manually aligned to the auxiliary feedwater pumps in the event of unavailability of the condensate storage tank.

For the SGTR discussed in Section 6.4.1.2 and for the Table 6.6-19 analysis, the steam releases have been maximized for purposes of providing a conservative calculation of radiological releases. Since these steam releases have been deliberately made conservative, they are not used to determine the required CST volume.

17 **In Sections 6.8.1 & 2 (ATWS) the AFW flow assumptions differ from those in Section 6.3. Are changes in AFW capability assumed for SPU conditions? If so, discuss, explain and justify the changes, and also, is NRC review and approval required?**

No changes in AFW flow capability are assumed or planned for IP2. This includes AFW system valves piping, and automatic actuation signals. The IP2 Auxiliary Feedwater System (AFWS) has two motor-driven (MD) AFW pumps (each pump aligned to 2 steam generators) and a turbine-driven (TD) AFW pump. All the pumps start automatically on an initiation signal, but the TD pump requires operator action to initiate flow to all 4 steam generators. The nominal design capacities of the IP2 AFW pumps are as follows:

- Motor-driven AFW pump - 400 gpm
- Turbine-driven AFW pump - 800 gpm

The analyses documented in Section 6.3 are safety analyses performed assuming a conservative set of analysis conditions which include meeting limiting single failure criterion. As a result, the AFW system capacity in the Section 6.3 analyses assume that a conservative AFW flow of 380 gpm is available from only 1 AFW pump (i.e., motor-driven pump).

The anticipated transient without scram (ATWS) analysis assumed nominal conditions consistent with the requirements outlined by the NRC. In consideration of the low probability of an ATWS, the NRC permitted nominal initial conditions, nominal system parameters and the availability of all system functions except reactor trip to be assumed. The SPU ATWS evaluation in Section 6.8 assumes a nominal AFW flow of 400 gpm per pump from 2 motor driven AFWPs consistent with the IP2 AFW system design capacities.

Therefore the difference in AFW flow capacities assumed between the Section 6.3 and 6.8 analyses are a result of a difference between the conservative/minimum and nominal design AFW system capacity assumptions. There are no changes in AFW system flow for the SPU that require NRC approval.

18 Explain why the Auxiliary Feedwater pump flow requirement to the steam generators is not affected by SPU operations (since reactor power and the resulting heat load is increasing).

The Auxiliary Feedwater System (AFWS) supplies feedwater to the secondary side of the steam generators at times when the normal feedwater system is not available, thereby maintaining the steam generator heat sink. The system provides feedwater to the steam generators during normal unit startup, hot standby, and cooldown operations and also functions as an engineered safety feature (ESF). In the latter function, the AFWS is required to prevent core damage and system overpressurization during transients and accidents, such as a loss of normal feedwater or a secondary system pipe break. In general, the accident and transient analyses of record had sufficient margin to accommodate the SPU power increase without changing the assumed AFW flow. Analyses of the limiting transients and accidents were performed to confirm that the AFWS performance is acceptable at the SPU conditions. For the IP2 SPU, these analyses demonstrate that the AFW system provides sufficient flow to achieve acceptable results at SPU conditions.

The limiting transient analyses requiring AFW are the loss of normal feedwater (LONF) and loss of all AC power (LOAC) to the station auxiliaries event. To support the SPU Program, a requirement was added for delivery of additional auxiliary feedwater (AFW) flow to preclude a pressurizer water-solid condition for these analyses. To ensure acceptable results were obtained in the LONF/LOAC event analyses (addressed in subsections 6.3.7 and 6.3.8 of the LAR), operator action was assumed at 10 minutes following reactor trip to provide additional AFW flow. The results of the accident analysis shows acceptable results with this flow assumption.

19 Any changes to operator response time that are assumed for the IP2 SPU and are less conservative than what was previously assumed should be discussed in detail and fully justified.

In support of this operator action time requirement in item 18 above, Section 10.15.1 states, "The EOP step for addition of supplemental feedwater to steam generators after a trip already exists and has been demonstrated to be accomplished in less than 10 minutes. This procedure will be revised to provide specificity for the flow and time requirements." This has been supported by simulator training tests for this action. The simulator training tests indicated that operators typically responded in less than ten minutes using the current procedures. The revisions to the procedures to identify the flow and time requirements will specifically identify the requirements for performing these actions.

20 In Section 6.3 (on page 6.3-6 and in Sections 6.3.7 and 6.3.8), there is a discussion of the use of operator actions to start an additional AFW pump within 10 minutes to preclude pressurizer water solid conditions from occurring during a loss of normal FW and during a loss of AC power to station auxiliaries analysis, thereby satisfying the acceptance criteria. Is this manual operator action currently required by the existing plant design & licensing basis?

See Responses to items 18 and 19. The LONF discussion addresses the use of operator action to start the second MDAFWP or to align the TDAFWP at 10 minutes after reactor trip on a low-low steam generator water level signal to deliver additional AFW flow to the 2 steam generators not already receiving AFW. The original and current licensing basis for IP2 allows operator actions to be credited at 10 minutes. While LONF analysis had not previously credited operator action at 10 minutes, other analyses had credited operator actions at 10 minutes (e. g., Main Steam Line Break– see NRC Safety Evaluation Report related to License Amendment 79 dated August 30, 1982).

Section 6.3.1 indicates that this is a new assumption for the LONF and LOAC analyses.

21 The acceptance criteria used for the Auxiliary Feedwater System does not appear to be complete (i. e., post-TMI action plan, HELB, fire, SBO). Provide confirmation that applicable design and licensing basis commitments are satisfied. (Section 9.12.4)

The AFW system must provide sufficient flow at the required head to obtain acceptable results for those analyses that require AFW flow for transient or accident mitigation. Section 9.12 lists the transients, accidents, and events for which AFW is required.

Licensing Basis Acceptance Criteria for the AFW System under SPU conditions include the following

- Loss of Normal feedwater

Provide sufficient AFW cooling to meet the acceptance criteria for LONF. (See Section 6.3.7)

- Rupture of a main steam line

Provide isolation of AFW to the faulted-loop steam generator to meet acceptance criteria for the Rupture of a Steam Pipe and for the MSLB events. (See Sections 6.3.11 and 6.6)

- Loss-of-coolant accident (LOCA)

Provide sufficient AFW to meet the acceptance criteria for LOCA. AFW has only a minor effect on LOCA analyses. (See Section 6.2)

- Loss-of-AC power (LOAC)

Provide sufficient AFW cooling to meet the acceptance criteria for LOAC. (See Section 6.3.8)

- Steam generator tube rupture (SGTR)

Provide AFW isolation early enough to prevent exceeding offsite dose limits. (See Sections 6.4 and 6.11.9)

- Anticipated transient without scram (ATWS)

Provide sufficient AFW cooling to prevent exceeding an RCS pressure Service Level C limit of 3215 psia. (See Section 6.8)

- 10 CFR 50 Appendix R Safe Shutdown / Alternate Safe Shutdown

Provide sufficient AFW cooling to remove decay heat and to cooldown the RCS to RHR entry conditions. This allows the Appendix R cooldown analysis to demonstrate the that the cooldown can be completed within the required 72 hours. (See Sections 4.1.3, 4.1.6, and 10.1)

- Station blackout (SBO)

Provide sufficient condensate inventory to remove decay heat and to cooldown the RCS to minimize RCS inventory loss. (See Sections 4.2 and 10.6)

- HELB

Refer to "Rupture of a main steam line" above.

- TMI Action Plan items

TMI Action Plan items for the AFW System, including system reliability analyses, re-evaluation of system design bases, and implementation of requirements for AFW automatic initiation and flowrate indication, continue to be met for SPU.

22 **As discussed in Section 6.6.4.5, the original analysis for the main steam line break outside containment assumed 900 seconds for operator action to terminate AFW flow and to close the MSIVs. Because 900 seconds was considered to be "excessively conservative", the PU evaluation changed the operator response time to 600 seconds. Please explain.**

This item deals with the operator action assumptions for the MSLB outside containment compartment analysis. The following text is contained in the LAR:

> "The computer simulations performed for the M&E release analysis were originally run assuming an operator action time of 900 seconds to terminate auxiliary feedwater flow and close the MSIVs. The operator action time of 900 seconds was later determined to be excessively conservative and a time of 600 seconds was determined to be conservative, but more realistic."

In the first sentence, the word "originally" refers to the first sets of computer runs made for the outside containment compartment analyses for the SPU. The IP2 MSLB outside containment compartment analysis that supports the current plant operation assumes 600 seconds (10 minutes) as the operator action time. In an attempt to develop more margin for the operators, the SPU assumption was set at 900 seconds (15 minutes) for the first set of analyses for the SPU. This assumption could not be supported by the analysis results and a decision was made to perform the SPU analyses with the current licensing basis analysis assumption of 600 seconds.

<u>Main Steam Supply System</u>

23 **For pump and valve programs, provide more details on how Entergy evaluated that the valves were acceptable for uprated conditions, giving examples of typical evaluations for different pump or valve types (e.g., relief valves, MSIVs). Also briefly indicate; 1) why there are no relief valve setting changes or pump change-outs, 2) whether the MSIV has a minimum close time limit, if the increased steam flow could reduce the MSIV closure time, and why the design and operating experience with the MSIV supports a finding that the closure time will not be affected, and 3) whether the ambient temperature increase has been evaluated for the GL 95-07 pressure locking and thermal binding issue. (Sections 10.2 and 10.10)**

As described in Section 10 of the IP2 Licensing Submittal for SPU, several valve programs were reviewed for the effects of SPU conditions. The Generic Letter 89-10 program for safety related Motor Operated Valves (MOVs) is addressed in Section 10.2. Generic Letter 95-07, evaluation of the susceptibility of power-operated gate valves to the phenomena of pressure locking and thermal binding, is addressed in Section 10.10.

The following is a discussion of evaluation of the effect of the SPU on the GL 89-10 MOV Program: For the systems containing MOVs in the GL 89-10 Program, the effect of the SPU on the operating conditions determined in the MOV differential pressure calculations (e.g., differential pressure, flowrate) were evaluated. For any identified changes in these operating conditions due to the SPU, evaluation of the affect on related GL 89-10 parameters (e.g., MOV thrust / torque values) was performed. It was concluded that any operating condition changes due to the SPU did not affect the current MOV thrust / torque values. A review was also performed to confirm that any changes in maximum ambient temperatures at locations of GL 89-10 MOVs due to the SPU do not affect the results of the existing evaluation of MOV motor torque degradation due to elevated ambient temperatures. The analysis of a steamline break inside containment under SPU conditions takes credit for operation of the feedwater flow control valve isolation MOVs. These valves were not previously credited in a safety analysis and are not currently included in the GL 89-10 Program. Accordingly, they will be added to the GL 89-10 Program.

The current Generic Letter 95-07 evaluation of power-operated valves (MOVs / AOVs) for pressure locking and thermal binding considered two types of pressure locking: pressure-induced pressure locking and thermal-induced pressure locking. Two types of thermal binding were also considered: seating effect and valve stem growth effect. However, only the valve stem growth effect was determined to be of potential concern. The results of the evaluation identified that potential pressure locking and thermal binding conditions will not prevent the plant from achieving safe shutdown, as all valves evaluated remain operable. This conclusion is based on valve design; plant configuration during normal, accident, and post-accident operating modes; and sufficient actuator thrust to open the valve. An assessment of the effect of the SPU on the current evaluation of each MOV / AOV for pressure locking and thermal binding was performed. It was concluded that the SPU does not introduce any increased challenge for thermal binding and/or pressure locking and does not affect the results and conclusions of the current evaluations.

Evaluations of the effects of SPU conditions on pumping systems and equipment were completed on a system basis. Each system was reviewed to determine if the system design remains within the existing design bounds. The results of the evaluations are included in the specific system section. NSSS system setpoint changes are included in Section 6. There were no BOP system setpoint changes or pump change outs required as the systems were found to be bounded by the existing design basis and capabilities of the equipment.

The MSIVs are required to prevent the uncontrolled blowdown of more than one steam generator and to minimize the RCS cooldown and containment pressure to within acceptable limits following a main steamline break (MSLB). To accomplish this function, the design requirements specify that the MSIVs must be capable of closure within 5 seconds of receiving a closure signal against steam break flow conditions in the forward direction. The MSIV is a non-return check valve type. There is no minimum MSIV closure time for these valves. The UFSAR describes the current design in Section 10.2.1 which states: "Each steam pipe has a swing disk type main steam isolation value (MSIV) and a swing disk type nonreturn valve located outside the containment. The MSIVs were redesigned to better withstand the dynamic forces associated with rapid closure in the event of a steam line rupture and thus reduce the likelihood of damage. The material for the valve discs was upgraded to stainless steel and the design of the disc arms was improved to reduce valve strains. In their Safety Evaluation Report (SER) dated September 15, 1976, the NRC determined that these modifications would satisfy General Design Criteria 4 of 10 CFR 50, Appendix A." The worst cases for differential pressure increase and thrust loads are controlled by the steam line break area (which controls mass flow rate and moisture content), throat area of the steam generator flow restrictors (1.4 ft^2 which limits the effective break area) , valve seat bore, and no-load operating pressure (which provides the highest initial main steam pressure for the MSLB). Since the SPU does not affect these variables, the design loads and associated stresses resulting from rapid closure of the MSIVs will not change. Consequently, SPU has no significant effect on the MSIV closure time.

The ambient temperature increase has been evaluated for the GL 95-07 pressure locking and thermal binding issue. It was concluded that the SPU does not introduce any increased challenge for thermal binding and/or pressure locking and does not affect the results and conclusions of the current evaluations.

24 A statement should be provided that describes the AFW pump turbine and startup supply line original design flow velocities and acceptance criteria to demonstrate that the existing design bases are satisfied.

The main steam system piping velocities were calculated and shown to increase for the SPU conditions. Percentage increases corresponded directly to flow increases of approximately 6%. For the main steam header piping from the steam generators, velocities were calculated as 161 fps. Velocities for normally operating branch line to auxiliary equipment were calculated in the range of 40 – 115 fps at SPU conditions. The calculated velocities were reviewed to the widely accepted industry standard velocity range of 100 to 167 fps for saturated steam. All steam line velocities were found to be within the widely accepted industry standards.

For lines that are infrequently used such as the auxiliary feedwater turbine supply and startup supply lines, a widely accepted industry standard velocity range of 250 fps was used. The auxiliary feedwater turbine supply and startup supply line velocities at SPU conditions remain unchanged and were calculated to be 41 fps, well within the widely accepted industry standards.

25 The discussion in Section 4.2.2.1, indicates that the Westinghouse steam dump sizing criterion of being able to discharge 40% of rated steam flow at full load steam pressure conditions is not satisfied. Section 4.3.1 NSSS plant operability analyses indicate that the steam dump capability is sufficient for a T_{avg} of greater than or equal to 562. Limiting T_{avg} to 562 is relied upon for meeting this requirement, but no technical specification restrictions have been established for T_{avg}, such that a 50% load rejection capability is assured. The capability of preventing main steam safety valve actuation following trips from full power given the allowable ranges of steam pressures and RCS temps have not been addressed.

The Westinghouse sizing criteria for the NSSS/BOP interface were originally established to provide guidelines to the BOP designer to ensure that the BOP design would be compatible with the NSSS. Following completion of the BOP designs for each plant, the BOP design parameters and capabilities were then used in the accident and transient analyses to demonstrate that the entire plant design had sufficient capability to accommodate accidents and transients that were postulated.

For the steam dump capability, the transient analyses in Section 4.3 are performed to demonstrate that the plant has sufficient capability to accommodate the postulated events. The analyses in Sections 4.3 demonstrate that the main steam safety valves will not actuate following trips from full power for ranges of steam pressures and RCS temperatures. As noted in Section 4.3, operation below T_{avg} of 558°F does not provide acceptable results, but the results indicate that operation at the planned T_{avg} of 562°F will provide acceptable operation. The plant has a requirement to maintain T_{avg} within the bounds established in the COLR, which contains requirements set for each reload cycle using methods that have been approved by NRC. These COLR limits are also provided in the plant operating procedures used in the control room. These reload-specific limits are supplemented by the accident and transient analyses that set analytical limits within which the reload analyese must be set. As noted in Section 4.3, the steam dump capability is acceptable if T_{avg} is greater than 558°F and the planned SPU operation will be at a T_{avg} of 562°F.

The steam dumps are discussed in the UFSAR in Sections 10.1.3, 10.1.4, 10.2.1.1, 10.2.1.2 and Table 10.3-1.

26 Provide a summary discussion of the basis for acceptance of the flow restriction nozzles for uprate conditions including worse case design, licensing basis considerations and acceptance criteria with a discussion of applicable bounding conditions and commitments and any exceptions thereto.

IP2 has two sets of main steam flow restrictor nozzles. The first set are welded into the SG outlet nozzles and are an integral part of those outlet nozzles. The SG outlet nozzles flow restrictor nozzles are designed to limit the blowdown flow from a downstream rupture in the main steam header. A second set of main steam flow restriction nozzles are located between the SG outlet nozzles and the MSIVs. These main steam flow restriction nozzles are designed to limit the blowdown flow from a downstream rupture in the main steam header and provide flow measurement of each steam header for plant control. Since the installation of the replacement SGs, the main steam flow restriction nozzles are not credited with limiting the blowdown flow from a downstream rupture in the main steam header. Section 5.6 addresses evaluations of the SG, including the SG outlet nozzle flow restrictors for the SPU conditions.

Section 6.6 of the LAR report provides a description of the main steam header rupture event assumptions and design parameters including a 2% power uncertainty factor (i.e. 102% NSSS power) with a double ended rupture and an effective break area of 1.4 sq ft in accordance with the licensing commitments described in IP2's Updated Final Safety Analysis Report Section 10.2.1. The break size is limited by the integral steam generator flow restrictor.

The second set of Main steam flow restriction nozzles are used to provide flow indication in the control room, input to the safeguards logic, input to the reactor trip logic and input to the steam generator water level control.

The main steam flow increase due to SPU conditions does not affect the functions associated with the main steam flow instrumentation or controls. Setpoint changes as required by SPU conditions are identified in Section 6.10 of the report. The nozzles and associated instrumentation were reviewed to verify that the process parameters associated with an approximate 6% increase in main steam flow due to SPU are within existing ranges.

27 Provide a summary discussion as to why the safety valves are acceptable for uprate conditions, including confirmation that existing design and licensing basis criteria and commitments will continue to be satisfied under SPU conditions. (Section 9.1.5.2.)

Section 4.2 describes the required capability of the Main Steam Safety Valves (MSSVs) as follows:

> IP2 has 20 safety valves with a total rated capacity of 15.108 x 10^6 lb/hr, which provides about 107.8 percent of the maximum SPU full-load steam flow of the 14.01 x 10^6.lb/hr (see Table 2.1-2, Case 3). Therefore, based on the range of NSSS design parameters for the SPU, the capacity of the installed MSSVs meets the Westinghouse sizing criterion.
>
> The original design requirements for the MSSVs (as well as the ARVs and steam dump valves) included a maximum flow limit per valve of 890,000 lb/hr at 1085 psig. Since the actual capacity of any single MSSV, ARV, or steam dump valve is less than the maximum flow limit per valve, the maximum capacity criteria are satisfied.

In addition to these statements, the MSSVs are also discussed in Section 9.1 and the capability of the MSSV is analyzed for the limiting Condition II design basis transient (Loss of Load event) in Section 6.3.6. The analysis in Section 6.3.6 demonstrates that the MSSVs are capable of maintaining the secondary side steam pressure below 110 percent of the steam generator shell design pressure.

Therefore the IP2 MSSVs are acceptable because the total valve capacity meets the original sizing criterion and the results of the LOL analysis show that the licensing basis acceptance criterion of maintaining SG pressure less than 110% of SG shell design pressure is met.

28 Provide a discussion that demonstrates the atmospheric relief valves' compliance with all existing design and licensing basis criteria. (Section 9.1.5.3)

In addition to LAR Section 9.1.5.3, the ARVs are discussed in Sections 4.2 and 4.3. The MSS includes four Atmospheric Relief Valves (ARVs) located upstream of the main steam isolation valves (MSIVs) and downstream of the main steam safety valves (MSSVs). The ARVs are automatically controlled by steam line pressure during plant operations. The ARVs automatically modulate open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined setpoint to minimize safety valve lifting during steam pressure transients. As the steam line pressure decreases, the ARVs modulate closed and reseat at a pressure below the opening pressure

The primary function of the ARVs is to provide a means for decay heat removal and plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the ARVs, in conjunction with the Auxiliary Feedwater System (AFWS), permit the plant to be cooled down from the pressure setpoint of the lowest set MSSVs to the point at which the Residual Heat Removal System (RHRS) can be placed in service.

To limit the frequency of main steam safety valve (MSSV) lifts, the setpoints of the ARVs are based on plant no-load conditions and the lowest MSSV setpoint. Since neither of these pressures changes for the proposed range of NSSS design parameters, there is no need to change the ARV setpoint.

These valves are designed to pass a total of 10 percent of full-load main steam mass flow rate at no-load steam generator outlet pressure. This capacity permits a plant cooldown to RHRS operating conditions (350°F) in 4 hours (at a rate of about 50°F/hr), assuming cooldown starts 2 hours after reactor shutdown. This sizing is compatible with normal cooldown capability and minimizes the water supply required by the AFWS. This design basis is limiting with respect to sizing the ARVs, and bounds the capacity required for tube rupture. An evaluation of the installed capacity (1,369,000 lb/hr at 1020 psia) indicates that the original design bases in terms of plant cooldown capability can still be achieved for the range of SPU NSSS design parameters

29 788 psia is credited in Section 4.2.3 as the full load steam pressure, inconsistent with the pressure credit in Section 4.2.2.1 for the steam dumps. All instances where criteria are not consistently used in the LAR should be highlighted to NRC for review and consideration.

The philosophy of design and analysis has evolved over the years. Original design criteria were established to ensure that the systems and components would have sufficient capability to accommodate accidents and transients within the licensing bases. For each event or analysis, specific methods of selecting input parameters and assumptions were established to make sure that each analysis was sufficiently conservative. Different events and different analyses of the same events may have different conservative directions for specific parameters. For example, the ECCS LOCA analysis seeks to minimize containment pressure, since that results in a conservative calculation of ECCS capability. The LOCA containment pressurization analysis seeks to maximize the containment pressure since that results in a conservative containment design capability. In Section 4.2.3 high Steam pressure is assumed to provide the maximum backpressure against which the feed pumps must deliver flow. In Section 4.2.2.1, the low steam pressure was selected to provide the limiting case for exhausting steam through the steam dump valves. Each analysis or evaluation states the assumptions used.

30 Provide a clarifying statement that the flow accelerated corrosion (FAC) program activities for the extraction steam piping and components will be continued. (Section 9.2.5.1)

The flow accelerated corrosion (FAC) program activities for the extraction steam piping and components will be continued.

The primary objective of the FAC program is to maintain the long-term process of FAC detection and monitoring in piping systems so that pipe wall thinning can be mitigated or reduced to prevent pipe failures. The major variables affecting the FAC process have been identified as flow path geometry, material composition, fluid temperature, flow velocities and flow restrictions, pH and oxygen, and moisture content. The criteria used to exclude non-susceptible piping segments from further FAC analysis included :

- Single phase systems in which the normal operating temperature at 100% power level is 200°F or less
- Piping systems constructed of materials other than carbon steels
- Piping containing fluids other than water or wet steam
- Raw water systems, e.g., service water and city water
- Systems with no flow or systems that operate less than 2 percent of the plant operating time.

The key evaluation processes of the FAC Inspection Plan are as follows:

- CHECWORKS modeled systems – the CHECWORKS computer model is used for pipe wear prediction to the extent applicable. Program sub-models include the Heat Balance Diagram. Input data to the CHECWORKS program include pipeline normal operating temperature and pressure (obtained from the Heat Balance Diagram) and flow velocity.
- Large bore NON-CHECWORKS systems
- Small bore systems (piping less than 2 inches in diameter is not modeled in CHECWORKS)
- Component reinspection – UT trending
- Closed and low-usage boundary valves
- Plant and industry experience

Main Condenser

31 **Explain the basis for condenser hotwell volume acceptance criteria (full condensate flow for 5 minutes) with respect to the required capability to accommodate plant transients and postulated accident conditions. (Section 9.4.4)**

Section 10.2.5 of IP2's Updated Final Safety Analysis Report (UFSAR) requires a condenser hotwell volume that includes a four (4) minute storage volume while operating at maximum turbine throttle flow with free volume for condensate surge protection.

Surge protection due to load rejection capabilities of the unit and recovered steam dump to the condenser without relying upon the reserve condensate storage is provided.

The condenser hotwell volume of 114,000 gallons provides for more than 5 minutes of condensate flow at SPU conditions.

Condensate and Feedwater System

32 **Please discuss the change of feedwater temperature responses affecting the current NSSS design transients.**

The SPU conditions used for NSSS design and safety analyses includes a feedwater temperature window (390-436.2). The NSSS design transient set for IP2 does not include transient feedwater temperature and flow as parameters to be used for evaluation of NSSS components. The RCS temperature, pressure and flow characteristics that are provided for evaluation of NSSS components are sufficient for all components except the secondary side components of the SGs for which the feedwater temperature range is specifically addressed.

33 **What analyses were performed to fully qualify condensate pump suction piping for the higher SPU temperatures and provide a summary of the analyses and results. (Section 9.4.5)**

The maximum normal sustained operating temperatures for the condensate pump suction piping (111°F @ 3.0 inch HgA condenser pressure) exceeds design temperature (100°F) by 11°F. The maximum sustained operating temperature for condensate pump suction piping will be 87°F @ 1.5 inch HgA condenser pressure and 75°F @ 1.0 inch HgA condenser pressure respectively. The IP2 operating test data indicates that condensate pressure varies from 1.0 inch HgA to 2.77 inch HgA at current conditions. The condenser and feedwater system has been evaluated based on 3.00 inch HgA condenser pressure heat balance for conservatism and additional margin. The materials of this piping are A672, grade A55 for pipe 30 inch to 54 inch, A53, grade B for 3 inch to 24 inch and A106, grade B for 2-1/2 inch and smaller. The pipe walls of condensate pumps suction piping from condenser are acceptable at SPU since the design pressure is 30 psig and the stress value of A53 Grade B material remains unchanged in the temperature range of -20°F to 650°F. So, by changing the design temperature to maximum normal sustained temperature, the existing pipe schedules will not change. Also, the rated pressure of valves/flanges at 111°F exceeds the design pressure of 50 psig.

34 **The discussion of feedwater isolation effects in Section 4.2.3.1, does not provide sufficient justification to demonstrate the previous analysis bounds SPU conditions.**

The worst loads occur following a steam line break from no-load conditions with the assumption that all feedwater pumps are in service providing maximum flow following the break. As noted in Tables 2.1-1 and 2.1-2 in the IP2 SPU LAR, no load temperature is 547°F. Saturation pressure is 1020 psia at 547°F. This provides the initiating conditions for which the valves would be required to function. The feedwater pumps would provide flow to the SGs at a pressure sufficient to feed the SGs with a SG pressure of 1020 psia. Since the SPU does not change the no load temperature, the previous analysis remains valid.

35 **The discussion of the feedwater regulation valves (FRV) & the condensate and feedwater (FW) pumps in Section 4.2.3.2, indicates that the lift of the FRVs at full power will increase by as much as 5.1% with the present FW pump speed control program. Does this evaluation demonstrate that existing plant design and licensing basis criteria are met?**

The lift of the FRVs will change by ~5% if the plant is operated at T_{avg} of 549°F with the present Feedwater Pump Speed Control Program. This design evaluation was performed to cover the entire operating window (T_{avg} from 549°F to 572°F). It also assumed that the Feedwater Pump Speed Control Program would not be changed. In practice, the plant will evaluate the Feedwater Pump Speed Control Program and the FRV lift at the actual plant operating conditions and make changes to the speed control program settings to maintain optimum FRV settings. The startup test plan includes items that will evaluate the need to adjust the Feedwater Pump Speed Control Program. Since the plant intends to operate at the current T_{avg} of 562°F, it is not likely that a significant change will be required.

36 **The discussion in Section 4.2 also concludes that the condensate feed system will maintain adequate FW pump suction pressure, assuming one drain tank pump remains in service following a large load rejection. Does this evaluation demonstrate that existing plant design and licensing basis criteria are met?**

An evaluation was performed to assess the C&FS hydraulic capability for a transient that results in the trip of 1 heater drain pump. The evaluation demonstrated that the MFW pump would have sufficient suction pressure to continue feeding the SGs. This evaluation demonstrates that the existing plant design capability for 50% load rejection is met.

37 **Provide a comparison of the extraction steam inlet nozzle velocities to design criteria values where the velocities exceed the design criteria and discuss the effect on plant operations. (Section 9.2.5.2)**

At the time that IP2 was constructed, no generic guidelines existed for feedwater heaters. Original Equipment Manufacturers (OEM) were relied upon to specify design requirements based on identified system parameter requirements. For the SPU, Heat Exchange Institute (HEI) nozzle velocity limits were used as the design basis guideline for the extraction nozzles. All calculated nozzle velocities were within the HEI guidelines except the low pressure feedwater heaters (21A, B, C and 22A, B, C). The velocities at SPU conditions associated with these low pressure feedwater heaters were calculated as 270 to 295 fps (for feedwater heaters 21A, B, C) and 210 to 235 fps (for feedwater heaters 22A, B, C). These values exceed the HEI limit of 215 (for feedwater heaters 21A, B, C) and 197 fps (for feedwater heaters 22A, B, C).

Based on the calculated velocities in these nozzles, no effect on plant operations is expected. These nozzles will be added to the existing IP2 FAC program to monitor and trend wall thickness. Entergy has contracted the OEM to reanalyze those feedwater heaters exceeding HEI guidelines.

38 **Provide a description of the measures that will be taken during startup testing including acceptance criteria to confirm that slug patterns do not occur in the extraction steam system piping. (Section 9.2.6)**

For extraction steam piping, potential flow regimes at SPU conditions are determined using long-accepted flow maps based on empirical data. The parameters predicted for SPU operation that result in the worst-case flow regime were taken from the output of one of the three SPU cases that included 0.5% margin. For horizontal sections of piping the Baker Two-Phase Flow Regime Selection Chart is utilized. For vertical up sections of piping the Griffith and Wallis Chart is used. For vertical down sections of piping the Oshino and Charles Flow Map is used.

SPU evaluations show that the horizontal portions of extraction steam system piping are predicted to either develop a semi-annular pattern at SPU operation or contain a liquid phase mass small enough to be carried over. The evaluation of vertical-up flowing portions of the extraction steam system piping at SPU operation indicate annular or mist flow patterns will likely develop and effective moisture carryover is expected. The calculated void coefficients associated with vertical-down flowing portions of the extraction steam system piping at SPU operation exceed 80% with margin so that slug flow patterns are not anticipated.

SPU startup testing will include verification of the SPU heat balance data. Also, as part of the normal plant surveillance during startup testing, walkdowns will ensure that piping sections are operating in the normal range.

39 **Heaters 22 emergency dump valves do not have sufficient flow capability to accommodate a heater tube rupture. Provide justification for not implementing modifications to restore the design capability of the 22 FW heater emergency dump valves to accommodate heater tube rupture. (Section 9.3.5)**

The design criteria for the emergency dump valves are to pass the mass flow resulting from a single double ended tube rupture or 10% of feed water flow. In the IP2 design, the 10% criterion is more limiting (at least 30% higher than the tube rupture flow) and has been conservatively used in our analysis. Assuming the 10% criterion, the emergency dump valves for heater 22 subsequent to SPU will be able to pass the mass flow from the more limiting 10% criterion.

In the IP2 design, the emergency dump valves are backed-up by a bypass line to the condenser. The bypass to condenser level control valves and emergency dump valves together are capable of draining the combined normal heater drain and a tube rupture flow with a 75% opening of the bypass to condenser level control valves and a nominal 62% opening of the emergency dump valves .

The IP2 dump design has diverse elements that make for a robust design. The system capability is not impaired at SPU conditions and modification is not necessary

40 **Provide a discussion of the measures that will be taken to monitor the small portion of the piping downstream of the reheater drain control valves in close proximity of slug flow.**

Vibration of piping downstream of the reheater drain control valves will be monitored as part of the piping vibration plan (see item 49) to assure that analytical results are correct.

41 **The design capacity of the 26 FW heaters relief valves are below HEI requirement of 10% feedwater flow. Describe how much below and justify why changes are not required.**

At the time that IP2 was constructed, generic guidelines existed for feedwater heater relief valves. For the SPU, Heat Exchange Institute (HEI) heater relief flow guidance was used as the design basis guideline for the relief valves. The design flow capacity of heater 26A/B/C relief valves (535 gpm) exceeds the HEI guidance of one double-ended tube rupture flow, but are slightly below the HEI guidance of 10% feedwater flow (by 12 gpm). In the event of heater tube rupture, the heater drain level control valves LCV1101, LCV1102 & LCV1103 will remain open and have adequate margin to drain the additional 12 gpm to heater drain tank to prevent over-pressurization of heater shell. During normal operation, the opening position of LCV1101, LCV1102 & LCV1103 is 48% - 56% to drain normal drain of heaters 26A/B/C to heater drain tank. Hence, the system capability is not impaired at SPU conditions and modification is not necessary.

42 Provide a summary description of the analyses for heater drain system piping and components where the design temperatures were exceeded.

The maximum normal sustained operating temperature of the heater drain tank drain line from the last stop valve (downstream of LCV) to the condenser (388°F) exceeds the design temperature (300°F) by 88°F. The maximum normal sustained operating temperature of reheater drain and vent lines from the last stop valve (downstream of LCV or HCV as applicable) to the condenser (479°F) exceeds the design temperature (300°F) by 179°F. The pipes are 8 inch Schedule 20, 14 inch Schedule 20, 3 inch Schedule 40 and 2 inch Schedule 40. The material of the piping is A53 Grade B. The allowable stress value of A53 Grade B material remains unchanged in the temperature range of -20°F to 650°F. So, by changing the design temperature to maximum normal sustained temperature, the existing pipe schedules will not change. The pipe walls are acceptable because the design pressure is 50 psig and the stress value is less than the stress allowable. The heater drain tank piping has ANSI 150 lbs flanges. The pressure rating of ANSI 150 lbs flanges is 183 psig @ 388°F which is higher than the design pressure of 50 psig.

The maximum normal sustained operating temperatures of heaters 26A/B/C shells (479°F) exceed the design temperature (450°F) by 29°F. The maximum normal sustained operating temperatures of heaters 24A/B/C shells (332°F) exceed the design temperature (325°F) by 7°F. The shells' materials of heaters 26A/B/C and 24A/B/C are SA516 Grade 70. The shell design of heaters 26A/B/C and 24A/B/C is not affected since the maximum allowable stress value of material SA 516 Grade 70 remains unchanged in the temperature range of -20°F to 650°F.

Based on the information provided above, the piping meets its design criteria and will function effectively for SPU conditions.

43 Some drain and vent piping and a number of inlet and outlet feedwater heater nozzles exceed industry flow rate criteria. List all the piping sections that exceed criteria and by how much. Provide justification for no plant changes

At the time that IP2 was constructed, no generic guidelines existed for feedwater heaters. The Original Equipment Manufacturer (OEM) were relied upon to specify design requirements based on identified system parameter requirements. For the SPU, Heat Exchange Institute (HEI) velocity limits were used as the design basis guideline for the heater drain piping and drain outlet nozzles.

All the heater drain piping flow velocities are within the maximum flow velocity criterion (4 ft/sec) except the flow velocities of drain piping from the heater drain tank to the condenser which have calculated flow velocities as follows:

Velocity for 24 inch pipe = 6.65 ft/sec
Velocity for 14 inch pipe = 6.70 ft/sec
Velocity for 4 inch pipe = 10.35 ft/sec

The flow velocities in the drain piping from the heater drain tank to the condenser were calculated very conservatively, assuming both heater drain pumps are inoperable and the drain lines are passing the full flow to the condenser. Although those calculated flow velocities exceed the maximum flow velocity criterion (4 ft/sec), this situation is extremely unlikely. Considering a more likely occurrence of a single heater drain pump failing, the flow velocities would reduce by one-half and only the 4- inch portion of this drain line would exceed the flow velocity criterion (calculated 5.2 ft/sec Vs. 4 ft/sec criteria). These lines are already included in the FAC Program to monitor and trend piping wall thickness.

Drain outlet nozzle flow velocities of heaters 26A/B/C, 25A/B/C, 23A/B/C & 21A/B/C exceed the HEI guidance (4 ft/sec) as follows:

Heater 26A/B/C: 5.28 ft/sec
Heater 25A/B/C: 3.27 ft/sec
Heater 23A/B/C: 4.36 ft/sec
Heater 21A/B/C: 4.27 ft/sec

Drain inlet nozzle mass velocities of Heater 22A/B/C (261 lbs/ft^2/sec) exceed the HEI guidance for mass velocity (250 lbs/ft^2/sec). In consideration of this condition, Entergy currently carries these nozzles in the FAC program to measure and monitor nozzle wall thickness as investment protection of a capital asset Hence, modification of these nozzles is not necessary.

44 **Discuss measures that will be taken during startup testing to assess performance of heater drain pumps and what restrictions will be established to ensure the pumps are operated in compliance with vendor recommendations and industry practices**

The heater drain pumps are capable of providing the required heat balance flow to feedwater pump suction at SPU conditions. Although pumps will operate near the runout point of the performance curve, they will not cavitate due to sufficient NPSHA with ample margin over NPSHR (NPSHA = 148 ft versus NPSHR= 36 for 100% SPU conditions). These pumps under current pre-uprate conditions operate successfully at flow rates close to runout. Cold water from the condensate system is injected into the pump suctions to improve the fluid conditions at the pump suctions and avoid cavitation problems. Their performance after SPU will be monitored in the startup test plan described in item 48 Table 1.

45 **How will analytical conclusions be confirmed during the startup program?**

The startup test plan has been developed to monitor specific areas. The SPU is not an uprate that takes the plant beyond the original design capability and therefore does not require that the original design capability be confirmed by performing extensive startup testing. See the startup test plan discussed in item 48.

Emergency Diesel Engine Fuel Oil Storage and Transfer System

46 **The discussion in Section 9.8 indicates that the EDG loading is acceptable. What effect does the SPU have on the EDG fuel oil storage and transfer system?**

The Emergency Diesel Engine Fuel Oil and Transfer System is not affected by the SPU. The subject area of Emergency Diesel Engine Fuel Oil and Transfer System effect due to the SPU has a bearing on Reactor Safety because the Emergency Diesel Engine must be able to support the Emergency Diesel Generator (EDG) operation throughout its design mission.

Evaluation of the effect of the SPU on the EDGs is provided in the LAR Section 9.8.1.8. The evaluation concludes that the loading on the EDGs resulting from SPU remains within the existing EDG load study. The demands on the Emergency Diesel Engine Fuel Oil and Transfer System are based on fuel consumption for the existing load study. Therefore the Emergency Diesel Engine Fuel Oil and Transfer System will provide sufficient fuel to support diesel requirements at SPU conditions.

Light Load Handling System (Related to Refueling)

47 **The Fuel Handling Accident dose considerations are discussed in Section 6.9.11.9.11. Please address the other aspects of fuel handling.**

The subject area of light load handling system has a bearing on nuclear Safety because criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures must be avoided.

There are no changes to the fuel handling equipment for the SPU. Entergy plans to implement an upgrade to the current fuel design at Indian Point Unit 2 (IP2) starting with Cycle 17 in November 2004. The upgrade basically consists of an enhancement to grid design to provide additional margin for grid-to-rod fretting, and the use of tube-in-tube guide thimbles to reduce the potential for incomplete rod control cluster assembly (RCCA) insertion. (See Attachment III item 1) There are no planned changes to the fuel assembly characteristics that interface with the fuel handling equipment (i.e. the lifting pockets of the top nozzle).

For the SPU, there is no change in the plant provisions for confinement of radioactive material, for shielding for radiation protection, or for criticality prevention. The source terms for normal operation (see Section 6.11.5) have been evaluated for the nominal increase in SPU power level and determined to have a very small effect on normal operation dose. The dose effects from a Fuel Handling Accident have been evaluated (see Section 6.11.9.11) and have been determined to meet acceptance criteria. The maximum permissible fuel enrichment and SFP boron Technical Specification are unchanged and therefore the criticality considerations are unchanged.

Startup Testing

48 **Describe measures that will be taken during PU startup testing to confirm that analytical results are correct, including test acceptance criteria that will be established to assure that PU operation is bounded by the analysis that was performed. (Section 9.0)**

The IP2 Test Plan has been designed to demonstrate that systems, structures and components will perform satisfactorily at the SPU condition. The plan provides assurances that (1) the initial power ascension to the SPU power level condition will be controlled, (2) the facility can be operated at the proposed SPU condition in accordance with design requirements and in a manner that will not endanger the health and safety of the public, (3) the SPU related modifications to IP2 have been adequately constructed and implemented.

A Temporary Operating Instruction (TOI) will be written to control the sequence and coordination of existing plant startup procedures with new post modification test procedures. It will ensure that the required modifications, calibrations, and specification requirements are in place to support the ascension to full power. Additionally, during the power ascension, the TOI will be used to callout or to verify the performance of specific test procedures, collection of plant performance data and documentation of the required reviews. Upon acceptance of plant data and test results, engineering and senior management will document their approval to proceed with the power ascension.

Additionally, Post Modification Tests (PMT) for each modification will be performed in accordance with plant design process procedures. The specifics of these PMTs are not detailed herein.

Pre Startup (2R16) Activities:

Material Degradation - Flow Accelerated Corrosion (FAC) Monitoring Program will be updated for the following areas, affected as a result of SPU:

24C Feedwater Heater inlet nozzle shell wall area

21ABC and 22ABC Feedwater Heater Impingement Baffle wear

Additionally, the projected SPU secondary heat balance parameters for temperature, pressures and velocities will be checked with the CheckWorks FAC program to ensure no unanticipated margins are reduced in advance of SPU.

Areas of increased monitoring, during power ascension:

1) Feed Water Heater Performance

   26 Feedwater Heater shell temperature (Evaluation by vender ongoing)

   21ABC and 22ABC Feedwater Heater Steam velocity and potential induced vibration (Evaluation by vender ongoing)

2) Reheat Moisture Separator drains, potential slug flows / vibrations.

3) Margin to OP/DT and OT/DT alarm / trip setpoints.

4) Heater Drain Pump runout and discharge valve control stability.

5) Main Boiler feed pump speed control circuit:

   a. Main Feed Regulator valve Delta P program circuit.

   b. Main Feed Regulator final valve position (lift).

6) Flow Induced Vibration on Main, Reheat, Exhaust Steam Systems.

7) Flow Induced Vibration on Condensate / Feedwater and HD Systems.

8) Plant operating control system performance.

IP2 SPU Test Plan

The following tables describe the testing and data collection for the SPU, related modifications and areas of increased monitoring. The test number to be performed on Table 1 is referenced on Table 2 at the respective Power levels. Piping Vibration testing is discussed in Item 49.

Item 48 Table 1 IP2 2 SPU to Original Design 3216 MWt		
System/Component	**Modification Description**	**Test**
Main Turbine	Replace the High pressure Turbine steam path	1- Vibration monitoring and harmonic vibration speed determination and Turbine differential expansion monitoring. 2- Over speed setting test 3- Demonstration of thermal performance improvements and generator increase.
Turbine Inlet Steam Pressure	Two pressure tap relocations from turbine 1st stage to inlet control stage (down stream of Governor valves)	1- Monitoring of Turbine Inlet Steam Pressure during ascension versus projection at hold points for plant calorimetric at 90%: 96.8% and 100%. Engineering evaluate deviations prior to power ascension approval. 2-Post Modification Test
Moisture Separator Reheaters	Replacement of lower separator baskets with counter flow Chevron design	1- Establish "as found" base line vibration data at current power level 3114.4 MWt 2- Monitor for flow induced vibrations during power ascension versus "as found." Engineering evaluate deviations prior to power ascension approval. 3- Monitoring during power ascension Steam flow, cross under ;cross over temperatures and pressures versus projected "PEPSE" secondary heat balance. Engineering evaluate deviations prior to power ascension approval. 4- Post Modification Test.
Heater Drain System	HDTP Discharge Valve Controls Mod. (Common controller for both valves in automatic, Coincident mod. not required for SPU)	1- Post Modification Test for discharge valve control circuit mod. Monitor stable operations of discharge valve controls during ascension. Engineering evaluate deviations prior to power ascension approval 2- Monitor HDTP & Motors Amps; Flows and discharge valve lift versus projected. Engineering evaluate deviations prior to power ascension approval. 3- Monitor for flow induced vibrations during power ascension versus "as found." Engineering evaluate deviations prior to power ascension approval. 4- Monitor FW Heaters levels and terminal drain temperatures versus expected PEPSE Heat balance projections.

Item 48 Table 1 IP2 2 SPU to Original Design 3216 MWt		
System/Component	**Modification Description**	**Test**
BOP system Main Steam / Extraction Steam / Reheat Steam / Condensate & Feedwater / Service Water System	Increase Steam and Feed flow for 3216 MWt	1- Establish "as found" base line vibration data at current power level 3114.4 MWt. 2- Monitor for flow induced vibrations during power ascension versus "as found." Engineering evaluate deviations prior to power ascension approval. 3- Monitor for flow induced vibrations post uprate plus 7 days versus "as left"(initial full power of 3216 MWt). Engineering evaluate deviations and recommend correction as necessary. 4- Monitor Main Boiler Feed Pump speed control; Delta P; Feed Regulating valve lift and Condensate Pump Amps versus expected. Engineering evaluate deviations prior to power ascension approval. 5- Monitor Service Water system loads : Main Turbine Generator (MTG) Hydrogen Coolers, MTG Exciter coolers, MTG Isophase Bus Duct coolers, temperatures & flows versus established "as found" base line data at current power level 3114.4 MWt. 6- Monitor FW Heaters terminal discharge temperatures versus projected. Engineering evaluate deviations prior to power ascension approval. 7- Monitor secondary plant oil cooling systems : MBFP / CP / HDT / MLO sys. versus expected and adjust as necessary.
MTG Isolated Phase Bus Duct cooling	Increase cooling coil water and fan air flow capacity. Replace flex link connections.	1- Monitor Cooling performance and fan motor. amps versus expected. Engineering evaluate deviations prior to power ascension approval. 2- Perform hot spot survey on ducts and evaluate. 3- Perform Hi Pot of flex links, insulators and evaluate. 4- Post Modification Test for cooling mod.
Main Power Transformer Monitoring	Installation of N_2 Gas monitor and removal of transformer. sound enclosures.	1- Monitor Cooling performance: at minimum and maximum Amp / VAR loading versus expected. Engineering evaluate deviations prior to power ascension approval. 2- Post Modification Test for monitoring system. 3- Perform Hot spot survey on MPT connections and evaluate.
RPS/ ESFAS setpoints	Rescaling transmitters ranges / resetting of NTS	1- Post Modification Test
Control System setpoints	Rescaling transmitters ranges / resetting of nominal control ranges.	1- Collect Plant data and confirm performance as expected. Evaluate adjustment as required. 2- Post Modification Test
Process computer	Engineering & alarm value update	1- Perform Pre-startup test. Monitor program functionality during power ascension. 2- Post Modification Test for Plant Computer Update.
Radiation Measurement	Power increase to 3216 MWt	1- Perform plant radiation surveys post power escalation to 3216 MWt. 2-Monitor and Adjust N-16 Main Steam Line Radiation Monitors.

Item 48 Table 2 IP2 SPU POWER ASCENSION TEST PLAN																	
Test/ Modification	Test Description	Rated Thermal Power % 3216 MWt (Allowance + / -.5%)															
		Prior To startup	0	5	10	20	30	40	50	60	70	80	90	93.4	96.8 Pre-SPU 100%	98.4.	100
Main Turbine	Table 1	2	1														3
Turbine Inlet Steam Pressure	Table 1	1							2		2		2		2	2	2
Moisture Separator Reheaters	Table 1	1									2		2 3		2 3	2 3	2 3
Heater Drain System	Table 1	1				1				2			1 3 4		2 3 4		2 3 4
BOP sys. MS / EST / RST / C& FW / SWS	Table 1	1											2 4		2 4 5 6 7	2 4 5 6 7	2 3 5 6 7
MTG Isolated Phase Bus Duct cooling	Table 1	1 3 4													2	2	1 2 4
Main Transformer Monitoring	Table 1	2													1 3		1 3
RPS/ ESFAS setpoints	Table 1	1											1		1		1
Control System setpoints	Table 1	1			1		1		1		1		1	1	1	1	1
Process computer	Table 1	1															1
Radiation Measurement	Table 1																1

Piping Vibration Testing Plan

49 Please provide a summary description of the piping vibration logic that will be used to develop the startup piping vibration test.

In response to feedback from other plants power uprate efforts, Entergy developed a piping vibration (PV) test plan. This PV plan considered plant condition reports written on piping vibration or support problems and plant piping and support evaluations or calculations for the effects resulting from SPU operating conditions. Based on this review the following Indian Point 2 (IP2) piping systems, affected by flow increases associated with SPU, were visually observed to determine if any existing pre-uprate vibration concerns exist.

Main Steam System
Extraction Steam System
Feedwater Heater Drains and Vents
Moisture Separator and Reheater Drains
Boiler Feedwater System
Condensate System

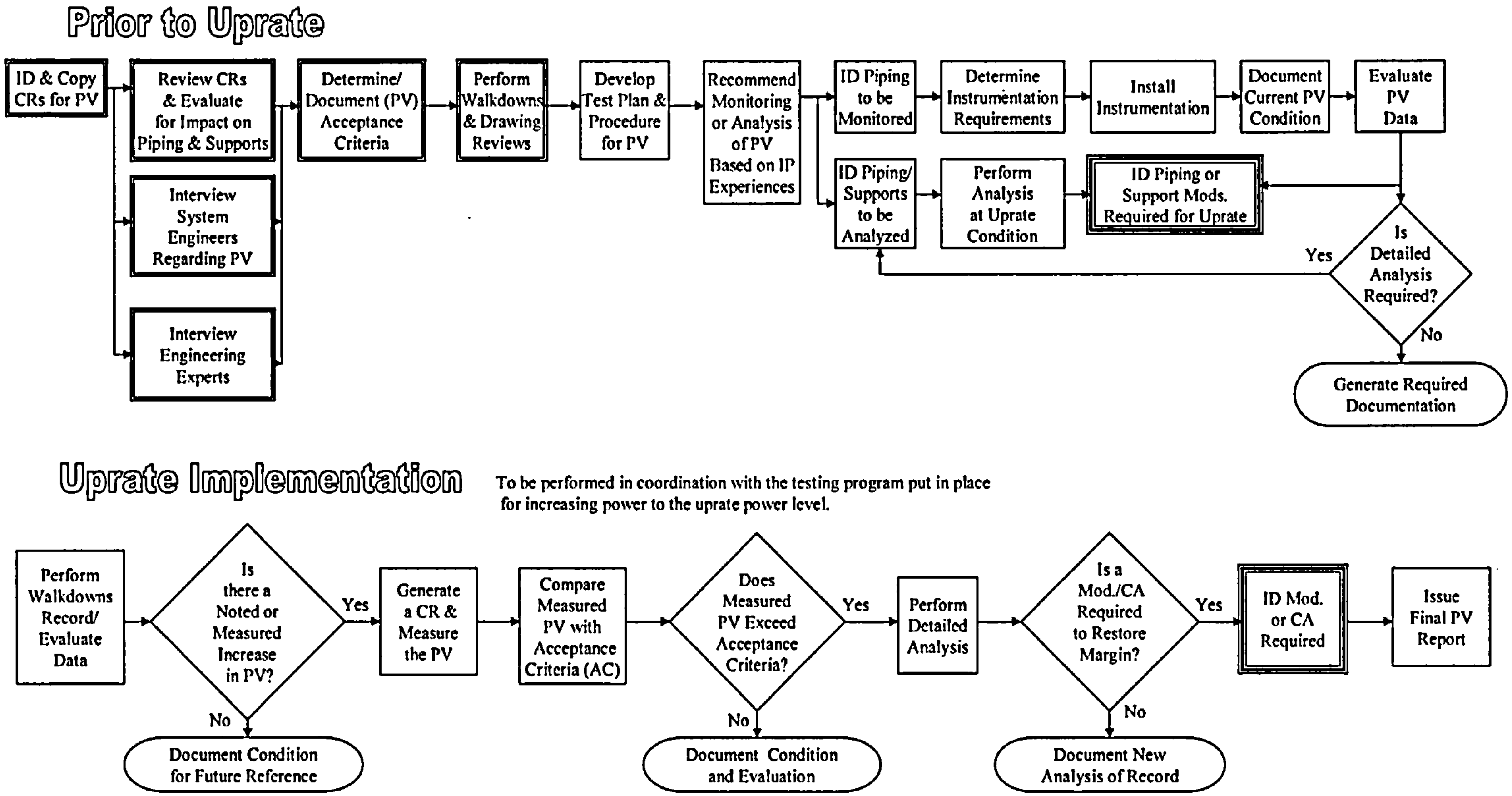
As a follow-up to the above pre-uprate visual observations, walkdowns will be conducted during the increase to SPU power. The acceptance criteria to be used during these walkdowns are intended to initially accept piping based on displacement or velocity screening criteria (based on observations of piping systems) and to collect data.

These criteria are limited to piping subjected to low frequency vibrations with predominant frequencies of less than 20 Hz.

Reference - Standards and Guides for Operation and Maintenance of Nuclear Power Plants, ASME OM-S/G-1994.

The attached Piping Vibration (PV) plan Logic is to be implemented during the power increase to the SPU power level.

Indian Point
Piping Vibration (PV) Plan Logic



ATTACHMENT III TO NL-04-039

IP2 STRETCH UPRATE LICENSE AMENDMENT REQUEST

ANSWERS TO QUESTIONS REGARDING

REVIEWS BY REACTOR SYSTEMS BRANCH

AND ELECTRICAL AND INSTRUMENTATION & CONTROLS BRANCH

PER 3/9/04 PUBLIC MEETING

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

Fuel System Design

1 Discuss the Cycle 17 Upgrade Fuel.

Entergy plans to implement an upgrade to the current fuel design at Indian Point Unit 2 (IP2) starting with Cycle 17 in November 2004. The upgrade basically consists of an enhancement to grid design to provide additional margin for grid-to-rod fretting, and the use of tube-in-tube guide thimbles to reduce the potential for incomplete rod control cluster assembly (RCCA) insertion. Westinghouse has already notified the NRC of this upgrade by letter LTR-NRC-04-8, dated February 6, 2004, "Fuel Criterion Evaluation Process (FCEP) Notification of the 15x15 Upgrade Design (Proprietary/Non-Proprietary)". This notification letter was sent to the NRC Document Control Desk with copies to J. Wermeil, F. Akstulewicz, B. Benney and E. Peyton. Please note that the FCEP notification letter includes a description of the fuel upgrade. Neither the FCEP notification letter, nor the IP2 SPU License Amendment Request (LAR) requests or requires NRC approval of the subject fuel upgrade. Since the thermal limits of the existing fuel at IP2 are the same as those for the upgrade fuel, the upgraded fuel product is not needed to support the validity of the SPU analyses and implementation of the SPU. However, the upgrade fuel does provide additional margin for grid-to-rod fretting and to reduce the potential for incomplete RCCA insertion. A mixed fuel core will exist at IP2 for the Cycle 17 reload; however, this has been addressed in, and bounded by the various analyses (both for the mixed cores that will exist in transition and the final equilibrium core of the Upgrade Fuel) that have been performed to support the IP2 SPU (as described in the IP2 SPU LAR (WCAP-16157-P). The core design of each future cycle at IP2 will also explicitly consider the consequences of mixed cores that may exist for each cycle.

Overpressure Protection during Power Operation

2 The primary and secondary systems safety valve capacities for IP2 were probably originally justified using WCAP-7769, Revision 1, "Overpressure Protection for Westinghouse PWRs", dated 1972. Since the surge rates for the safety valves under pressurization transient conditions would likely be affected, it should be confirmed that this report still applies to IP2.

Entergy confirms that WCAP-7769, Revision 1 did originally justify the reactor coolant system (RCS) and main steam system (MSS) safety valve capacities for IP2 relative to the overpressure acceptance criterion (i.e., 110% of design pressure for each system).

Entergy confirms that RCS and MSS safety valve capacities identified in WCAP-7769, Revision 1 still apply to IP2. As described in Section 6.3.6 of Attachment III to the submittal, the limiting RCS and MSS overpressure event, Loss of Electrical Load / Turbine Trip (LOL/TT), was analyzed at Stretch Power Uprate (SPU) conditions to demonstrate that the RCS and MSS overpressure acceptance criteria (i.e., 110% of design pressure for each system) will continue to be met. The SPU analysis confirmed that when modeling the pressurizer safety valve (PSV) capacity of 408,000 lbm/hr/valve for each of the three PSVs at IP2, the RCS overpressure acceptance criterion is met. The analysis also confirmed that when modeling the total main steam safety valve (MSSV) capacity of 15,108,000 lbm/hr at IP2, the MSS overpressure acceptance criterion is met. Again, these PSV and MSSV capacities are consistent with past IP2 analysis assumptions as documented in Topical Report WCAP-7769, Revision 1.

Spent Fuel Storage

3 Discuss the applicability of either 10CFR50.68 or 10CFR70.24 to the Spent Fuel Pit.

The requirements of 10 CFR 50.68(b) apply to IP2, and remain valid for the upgrade fuel design. As discussed in Attachment III item 1, the main changes in the upgrade fuel assembly are grid changes and the grids are not modeled in the 10CFR 50.68(b) analyses. Further, the current criticality analyses use Zircaloy/Zirc-4 while the upgrade fuel assembly will use ZIRLO. Since ZIRLO has a slightly higher absorption of neutrons, the current analysis remains bounding.

Steam Generator Tube Rupture

4 Discuss the assumption of termination of the break flow in 30 minutes following a design basis SGTR event is valid for IP2 at the uprated power level of 3216 MWt and will indeed lead to a bounding calculation regarding to the radiological consequences of the event. (Section 6.4.1.1)

Although the analyses that provide the break flow input to the dose analyses assumed termination of break flow at 30 minutes, an additional evaluation was performed with a more realistic set of conditions to verify that termination of break flow at 60 minutes is less limiting than the 30 minute case with constant break flow. Entergy has performed simulator studies and training to ensure that operators can terminate break flow within 60 minutes. This is covered in Section 6.4.1.1 on page 6.4-2.

Instrumentation & Controls

5 The NRC staff has recently become aware, and has discussed with NEI, a problem with use of instrument setpoint methodology if based on "Method 3" of ANSI/ISA-S67.04, "Setpoints for Nuclear Safety-Related Instrumentation." Does Indian Point 2 use this method? In describing the setpoint methodology used for IP2, please provide additional information associated with how channel operability is determined.

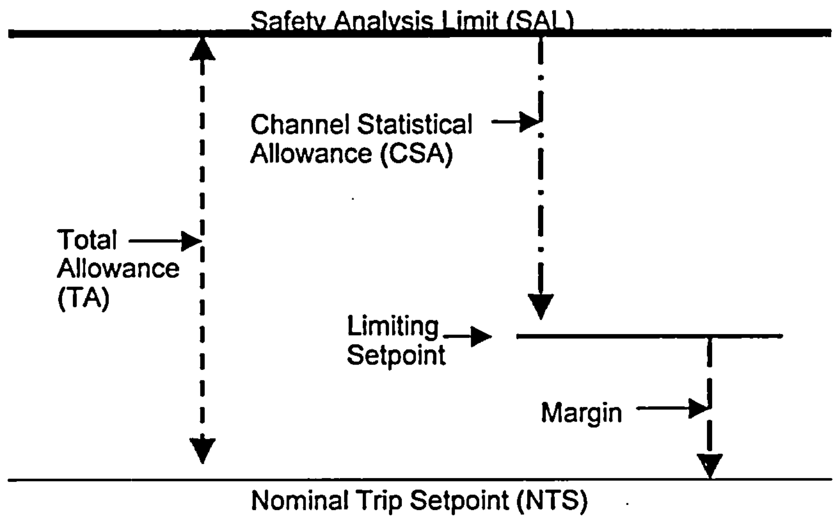
Indian Point 2 Setpoint and Allowable Value Determination

The methodology used for determining technical specification allowable values (AV) for the IP2 protection systems (RPS and ESFAS) is described in Entergy Specification FIX-95-A-001, Revision 1 which was submitted to the NRC in Entergy letter NL-03-117, dated July 18, 2003, as part of the license amendment for conversion to the Improved Standard Technical Specifications. This specification establishes a methodology equivalent to that described in ISA RP67.04, Method 2.

The following discussion uses the ESFAS High Steam Generator Water Level - Feedwater Isolation function as an example.

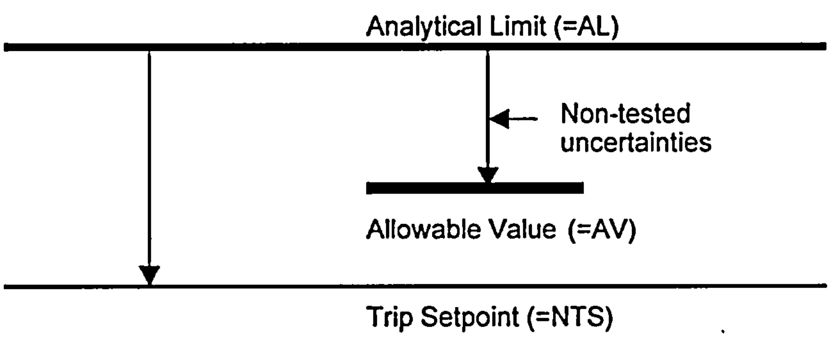
The following diagram (not to scale) identifies key terminology used in the setpoint calculations. Steam Generator Water Level indicates in % water level with a span of 0% to 100%. The Safety Analysis Limit (SAL) proposed for the High Steam Generator Water Level - Feedwater Isolation function at SPU conditions is 90%. This is an increase from the current SAL of 80% as described in Table 2 of Attachment I to this letter. The nominal trip setpoint (NTS) currently used for this function is 73%. This NTS value will be retained for SPU conditions. Total Allowance (TA) is the difference between the SAL and the NTS. TA in this example is 17%. The Channel Statistical Allowance (CSA) is the statistical combination of the instrument channel uncertainty components. CSA in this example is 4.9%. Margin is defined as the difference between the TA and CSA, in this example 12.1%. The acceptance criterion for the RPS/ESFAS setpoints is that the margin is greater than or equal to zero. The Limiting Setpoint is the SAL minus the CSA, which for this example is 85.1%. Entergy has confirmed that all RPS/ESFAS NTS values are conservative with respect to their associated Analytical Limits (SAL) by an amount equal to or greater than the Channel Statistical Allowance (CSA), which is equivalent to the total loop Channel Uncertainty.

IP2 Setpoint Methodology



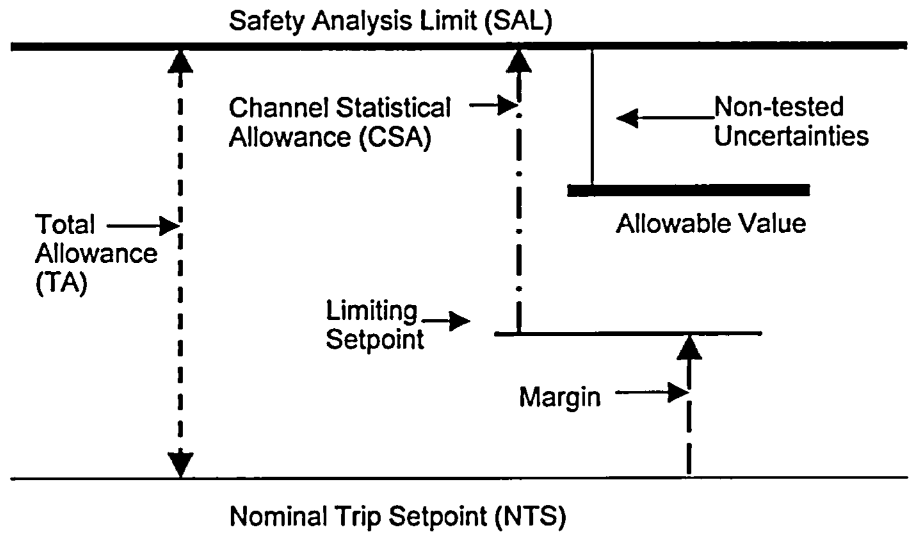
Per ISA RP67.04 the Allowable Value in Method 2 "...is determined by calculating the instrument channel uncertainty without including...drift, calibration uncertainties, and uncertainties observed during normal operations...This result is then subtracted from the analytical limit (AL) to establish the AV...the trip setpoint is determined as described in 7.2." Section 7.2 of RP67.04 describes a setpoint determination methodology similar to that described above for IP2.

ISA RP67.04 Method 2



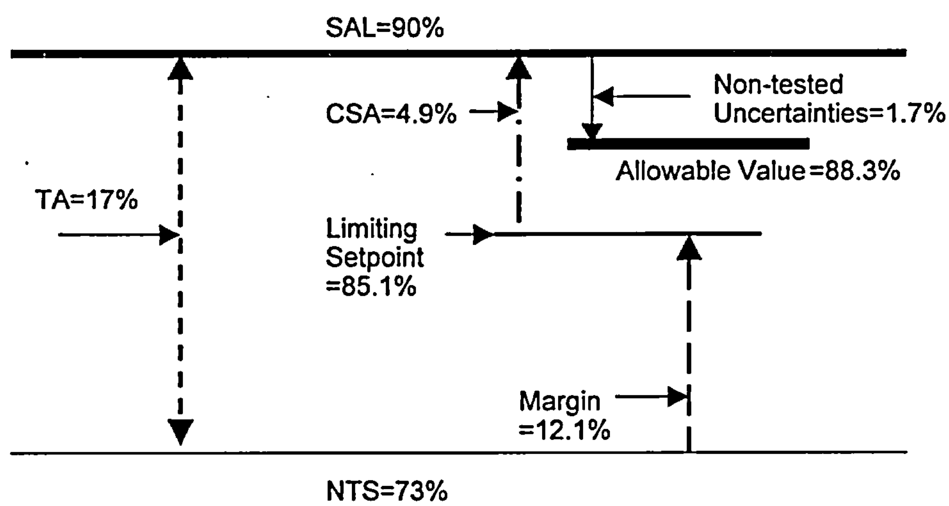
The Allowable Value is superimposed on the Setpoint Methodology graph below. Per Entergy specification FIX-95-A-001 Revision 1 errors due to the process, primary element, and temperature effects as well as biases are included in the determination of the Allowable Value.

IP2 Setpoint Methodology with Allowable Value



For Steam Generator High Level the non-tested uncertainties are calculated to be 1.7%. Subtracted from the SAL of 90% this yields an Allowable Value of 88.3%.

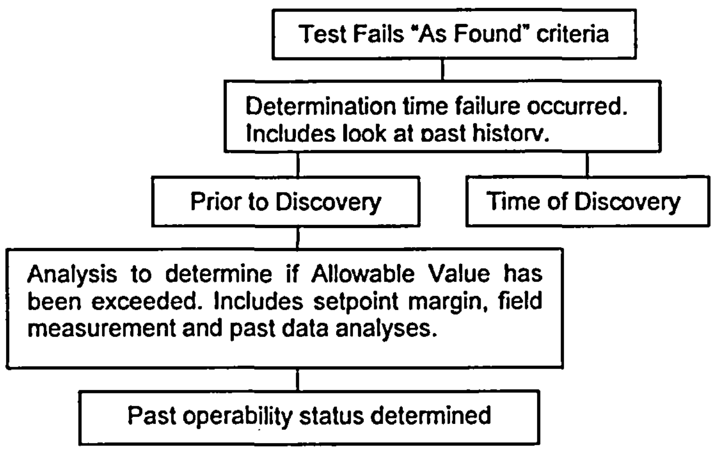
Steam Generator High Level example



Determining Operability at IP2

IP2 Channel Calibration surveillance tests contain "As Found" criteria to which the "As Found" data is compared. The "As Found" criteria are not Allowable Values, but are more conservative values to account for the fact that each device is part of a loop of devices. The steps for determination of past operability are contained in the IPEC Drift Monitoring Program procedure. When a bistable, transmitter or intermediate signal processing device fails its "As Found" criteria, a Corrective Action Program Condition Report will be written. This will trigger an analysis of the entire loop to determine if the Allowable Value has been exceeded. The analysis includes consideration of setpoint margin and, if necessary, the actual errors in other components in the loop. Combination of new field measurements and past data will be used in the analysis. Data is combined algebraically.

IP2 Past Operability Process



RTD Replacement Project

6 Please provide information regarding the IP2 RTD Replacement Project.

Each RCS hot leg and cold leg has three narrow-range, direct-immersion RTDs threaded into the mounting bosses and seal welded. For each hot leg and cold leg, the existing direct immersion RTDs will be removed. New thermowells will be threaded into the bosses and seal welded similar to the existing RTDs. New, well-mounted dual-element RTDs will be inserted into two of the three thermowells. The third thermowell will be capped for future use. To be consistent with the other loops, two of the RTD locations in the 22 Hot leg will be relocated to the opposite side of the pipe.

Four existing Foxboro RTD R/E Analog Converter Modules (for the cold leg loops), located in the CCR, will be replaced with similar NUS Analog modules. The four hot leg loop RTD R/E Analog Converter Modules were already replaced with similar NUS Analog modules in 2002. These modules perform reactor protection functions and shall be qualified to IEEE 344-1975.