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Fred Dacimo
Site Vice President
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September 24, 2004

Re: Indian Point Unit No. 2
Docket No. 50-247
NL-04-121

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

SUBJECT: **Reply to Request for Additional Information Regarding <u>Indian Point 2 Stretch Power Uprate (TAC MC1865)</u>**

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

Dear Sir:

This letter provides additional information, requested by the NRC during recent telephone conference calls, regarding the license amendment request submitted by Entergy Nuclear Operations, Inc (Entergy), in Reference 1. The requested information, provided in Attachment 1 does not alter the conclusions of the no significant hazards evaluation that supports this license amendment request.

There are no new commitments identified 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 September 24, 2004.

Sincerely,

Fred R. Dacimo
Site Vice President
Indian Point Energy Center

cc: next page

A001

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ATTACHMENT 1 TO NL-04-121

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING

PROPOSED LICENSE AMENDMENT REQUEST FOR

INDIAN POINT 2 STRETCH POWER UPRATE

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

Additional information requested by NRC staff via telephone conference calls in August and September, 2004.

NRC Item 1:

Recognizing the small decrease in the T_{cold} lower design value corresponding to a lower bound full-power programmed T_{avg} of 549°F for some components could be significant for fatigue evaluation, verify that the current design basis calculations have sufficient margin for all RCS components (RV, RVIs, piping/supports, pressurizer, RCPs, and SGs).

Entergy Response:

The only evaluations for which lower bound T_{cold} is limiting and for which a value of 515.5°F was used are the RCPs and the pressurizer spray nozzle. Engineering judgment indicates that sufficient margin is available to accommodate a 1.5°F change. Nevertheless, as indicated in Note 7 for Table 2.1-2 (of WCAP 16157 submitted by NL-04-005), actual operation of Indian Point 2 (IP2) is limited to a minimum T_{cold} of 525°F to support the vessel integrity calculations discussed in subsection 5.1.2 of the WCAP. Based on this limit, evaluations of NSSS components for a T_{cold} of 514°F or a T_{cold} of 515.5°F bound the actual operation of IP2 at the SPU power level. Structural evaluations of individual NSSS components are documented in Chapter 5 of the WCAP and show that stress and fatigue limits are met for the SPU evaluation conditions.

NRC Item 2:

The Entergy response for Piping and Supports Question 1, in letter NL-04-095 dated August 3, 2004, provides a stress summary table for main steam piping. Please provide similar quantitative results for evaluations performed for other balance-of-plant (BOP) piping systems.

Entergy Response:

Stress summary tables are provided below, as requested, for other BOP piping systems. These four systems reflect the next four SPU-sensitive systems after Main Steam. Pipe stresses were assessed based on pre and post SPU system conditions. The results presented include existing stress levels (i.e., pre-SPU), revised pipe stress levels for post-SPU conditions, allowable stress for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile SPU conditions. The design margin provided is based on the ratio of the calculated post-SPU stress divided by the allowable stress.

Table 1 Condensate System Stress Summary

Piping Analysis Description	Loading Condition	Existing Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Margin
Heaters 25A/B/C to FW Pumps	Thermal	15,724	15,886	22,500	0.71

Response to Item 2, continued

Table 2 Feedwater System Stress Summary					
Piping Analysis Description	Loading Condition	Existing Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Margin
Feedwater to SG 22	DL + LP	8,614	8,812	15,000	0.59
Feedwater to SG 22	Thermal	17,456	17,784	22,500	0.79
Feedwater to SG 23	DL + LP	8,507	8,705	15,000	0.58
Feedwater to SG 23	Thermal	4,317	4,441	22,500	0.20
Feedwater to SG 24	DL + LP	8,363	8,561	15,000	0.57
Feedwater to SG 24	Thermal	9,679	10,085	22,500	0.45

Table 3 Extraction Steam System Stress Summary					
Piping Analysis Description	Loading Condition	Existing Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Margin
Extraction Steam to Heaters 23A/B/C	DL + LP	1,873	1,892	15,000	0.13
Extraction Steam to Heaters 23A/B/C	Thermal	4,966	5,054	22,500	0.22

Table 4 FW Heater Vents and Drains System Stress Summary					
Piping Analysis Description	Loading Condition	Existing Stress (psi)	SPU Stress (psi)	Allowable Stress (psi)	Design Margin
Heaters 24A/B/C to Heaters 23A/B/C	DL + LP	1,819	1,837	15,000	0.12
Heaters 24A/B/C to Heaters 23A/B/C	Thermal	14,262	14,499	22,500	0.64

Note: Loading Condition DL + LP corresponds to the combination of stresses due to deadweight + pressure.

NRC Item 3:

Verify that controls are in place to assure that PCT sensitive parameters used in LOCA analyses bound plant-operating conditions.

Entergy Response:

Entergy Nuclear Operations, Inc. and Westinghouse have on-going processes which assure that the ranges and values of LOCA analyses inputs for Peak Cladding Temperature (PCT) sensitive parameters bound the as-operated plant ranges and values for those parameters.

NRC Item 4:

The Entergy response for Steam Generator structural integrity RAI 3 in letter NL-04-073, dated June 16, 2004 applies a quality factor of 0.5 for determining the stress acceptance criteria. Please explain the use of this factor.

Entergy Response:

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

NRC Item 5:

The Licensing Report (WCAP 16157 submitted by NL-04-005) describes the time to boil upon loss of cooling to the spent fuel pool changing from 1.8 hours to 1.67 hours. Discuss this change which the staff considers a change to the licensing basis needing prior NRC approval.

Entergy Response:

Entergy has reevaluated the time to boil estimate for the IP2 SPU and the existing 1.8 - hour time to boil estimate is maintained.

NRC Item 6:

Table 5.9-5 of WCAP 16157-P provides information regarding the fracture integrity evaluation for the pressurizer. The table indicates use of a flaw depth less than "¼ t " for the corner region of the safety and relief nozzles (0.5 inch flaw size used) and for the upper shell (0.15 inch flaw size used). Since these values do not meet the requirements of Appendix G of Section III of the ASME Code please cite the staff safety evaluation that approved the use of flaw sizes less than "¼ t " or provide other explanation regarding use of the specified flaw sizes.

Entergy Response:

In order to quantify the acceptable flaw size for the IP2 pressurizer upper shell and the safety and relief nozzles, an analysis using the ASME code Section III, Appendix G requirements was performed. This analysis was recently revised. The fracture mechanics analysis for the IP2 pressurizer upper shell has been revised to consider an updated technical evaluation of the spray characteristic of the inadvertent spray transient based on tests and analytical solutions that showed the spray droplet envelope remains well removed from the pressurizer wall at pressures above 1030 psia. This fracture mechanics analysis also included modified through-wall stresses for the governing location. Since the section thickness for the upper shell is 4.1875 inches, a 1/4t (1.05 inches) deep defect was conservatively postulated per Paragraph G-2120 of the ASME Code, Appendix G 1998 Edition. The analysis for the safety and relief nozzle was also revised using modified through-wall stresses. A defect of 1 inch was again postulated since the section thickness of the governing location for the pressurizer safety and relief nozzle is less than 4 inches. The results show that the maximum stress intensity factor K_I for the governing transient is less than K_{IR}. Therefore, it is concluded that the Indian Point Unit 2 Pressurizer Upper Shell and Safety & Relief Nozzle are in compliance with the ASME Code, Section III, Appendix G 1998 Edition requirements for the SPU conditions. The results are summarized below.

Fracture Integrity Evaluation Summary Indian Point Unit 2 – Pressurizer Upper Shell and Safety & Relief Nozzle			
Location	**Governing Transient**	**Flaw Depth (inch)**	**K_I/K_{IR}**
Upper Shell	Loss of Load	1/4t (1.05)	0.73
Safety & Relief Nozzle	Loss of Load	1	0.66

NRC Item 7:

During a CVCS malfunction to induce a boron dilution transient, Entergy chose to use a mixing volume that is equal to the RHR and RCS volumes. This appears to be non-conservative. The staff feels that the transient involves, conservatively, only diluted water from the primary water storage tank is injected into the cold leg through the charging lines at maximum letdown rate. This flow would then only mix with the volume of water in the cold leg and downcomer and lower plenum provided the RCPs were on. If they are not on, then there is less justification for mixing and it may be a dilute slug entering the core to cause a local power spike. The staff questions why the licensee is assuming RHR and RCS volume as the mixing volumes.

Entergy Response:

The CVCS malfunction event is discussed in WCAP-16157 Licensing Report Section 6.3.5. The question is best addressed by plant mode and the operation of the Reactor Coolant Pumps and the RHR System.

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

Modes 4 and 5: At least one Reactor Coolant Pump is in service on shutdowns until Reactor Coolant System temperature is less than approximately 170°F. The RHR System is placed in service when the Reactor Coolant System temperature is less than approximately 350°F thus assuring adequate mixing. Similarly, during startup, the RHR System is in service and a Reactor Coolant Pump is placed in service while Reactor Coolant System temperature is less than 200°F. In addition, the Westinghouse Interim Operating Procedure was developed specifically for these modes, addressing the potential effects of a "dilution front" and a limited active mixing volume, and has been incorporated in plant procedures. The discussion of the supporting analysis for this event was held with the staff in a September 8, 2004 phone call.

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

Mode 6: At least one RHR pump (providing a minimum flow rate of 1000 gpm) is in service except during short periods. This flow rate is considered adequate for mixing in the lower plenum. The actual flow from one RHR pump would be much higher than 1000 gpm. While the CVCS Malfunction event has been analyzed in the refueling mode, it is administratively precluded. Prior to entering Mode 6 (Refueling), plant procedures require implementation and documentation that dilution paths are isolated. The Indian Point Unit 2 UFSAR will be revised to reference the plant procedures that preclude conditions that would lead to boron dilution in Mode 6.

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

The staff also requested additional information on how the calculations were performed. The discussion below provides the information requested:

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

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

Where:

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

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

NRC Item 8:

Section 5.10.4 of the Stretch Power Uprate Licensing Report (WCAP-16157) provides an estimated increase in PWSCC susceptibility of 31 percent for the reactor pressure vessel head penetrations as a result of the stretch power uprate. An increase of greater than 20 percent is considered by the NRC staff to be significant. Please provide additional information regarding the estimated increase in PWSCC susceptibility and is there a plan for RPV head replacement.

Also, Section 5.10.4 of the Stretch Power Uprate Licensing Report provides an estimated increase in PWSCC susceptibility of 12 percent for the RV hot leg nozzle weld as a result of SPU. How will the 12 percent increase be accommodated in the future?

Entergy Response:

The approach used in Section 5.10.4, was to estimate a relative effect of PWSCC susceptibility by estimating the temperature change in the upper head region based on a conservatively wide range of operating temperatures that correspond to a full-power programmed Tavg range from 549 ^{o}F to 572 ^{o}F. The resulting temperature increase of 3.88 ^{o}F was evaluated using the crack initiation probability methodology described in Reference 2 of Section 5.10.

In practice, Entergy is required to establish RPV head inspection requirements in accordance with NRC Order EA-03-009. The Order provides for a time-at-temperature methodology to determine the effective degradation years (EDY) value that is used to determine the inspection category. Based on the current plant operating history and cycle-specific temperature data, the projected EDY value applicable for the next refueling outage (Fall 2004) is 9.6 years. The current temperature used for this analysis is 590 ^{o}F, and the current EDY accumulation rate is less than 0.7 EDY per effective full power year of operation. At the current power level, the transition from the moderate susceptibility category to the high susceptibility category (12 EDY) would occur for the inspection during the Spring 2010 refueling outage.

Using a conservatively high estimate of 4 ^{o}F for the effect of SPU on the temperatures in the upper head region, the EDY accumulation rate increases to less than 0.8 EDY per effective full power year of operation. Under these conditions, the transition from the moderate susceptibility category to the high susceptibility category could potentially occur one refueling outage earlier (Spring 2008). In that case the applicable inspection requirements would be implemented at that time. However, since the actual planned full-power programmed Tavg for SPU (562 ^{o}F) is less than the upper value evaluated, the effect on the upper head temperature would also be less than the 4 ^{o}F used in this evaluation. As required by the NRC Order, Entergy will recalculate the EDY value to establish the inspection requirements for each refueling outage using plant data for each operating cycle.

Entergy is assessing options to mitigate the effects of PWSCC on continued plant operation. One possible option involves a modification that would result in reduction of the upper head temperature. Entergy is also assessing eventual replacement of the reactor vessel head.

A similar assessment of PWSCC susceptibility for the RCS hot leg nozzle welds was performed. Although the NRC Order does not establish EDY categories and inspection requirements for these locations, Entergy is required to inspect these areas in accordance with ASME Section XI and the IP2 Inservice Inspection Program. Also, Entergy is participating in industry programs that monitor operating experience and develop recommendations, including augmented inspections. MRP has recently issued recommendations (MRP 2003-039, dated January 20, 2004) that include visual inspection of the hot leg nozzle welds. During the upcoming refueling (Fall 2004) Entergy will be performing volumetric NDE of these welds as part of the 10-year ISI inspection program. This inspection exceeds the visual inspection recommendations of MRP 2003-039.

Additional Item From Entergy:

Attached is an update for the reply to LOCA Transient Question 4, previously provided in Entergy letter NL-04-100 dated August 12, 2004. This update reflects a correction to results reported for heat transfer in the downcomer region, which has a small effect on Figures 1 through 4, but the conclusion regarding the time to reach stable and sustained quench for LBLOCA is not changed by this correction.

UPDATED REPLY TO LOCA TRANSIENT QUESTION 4
(Replaces response previously provided in NL-04-100, dated August 12, 2004)

LOCA Transient Question 4:

Provide the LBLOCA analysis results (tables and graphs, as appropriate) to the time that stable and sustained quench is established.

Response:

In order to demonstrate stable and sustained quench, the WCOBRA/TRAC calculation for the maximum local oxidation analysis was extended. Figure 1 shows the peak cladding temperatures for the five rods modeled in WCOBRA/TRAC. This figure indicates that quench occurs at approximately 275 seconds for the low power rod (rod 5), 400 seconds for the core average rods (rods 3 and 4), and 500 seconds for the hot rod (rod 1) and hot assembly average rod (rod 2). Once quench is predicted to occur, the rod temperatures remain slightly above the fluid saturation temperature for the remainder of the simulation. Figure 2 shows the collapsed liquid level in the four downcomer channels and shows steady behavior, with the level in each quadrant remaining near the bottom of the cold leg. Figure 3 shows the collapsed liquid level in the four core channels and indicates a gradual increase in the core liquid inventory. This is consistent with the expected result based on the removal of the initial core stored energy and the gradual reduction in decay heat. Figure 4 shows the vessel liquid mass and indicates stable and increasing trend beginning at about 700 seconds. This indicates that the increase in inventory due to the pumped safety injection is more than offsetting the loss of inventory through the break. Based on these results, it is concluded that stable and sustained quench has been established for the Indian Point Unit 2 Large Break LOCA analysis.

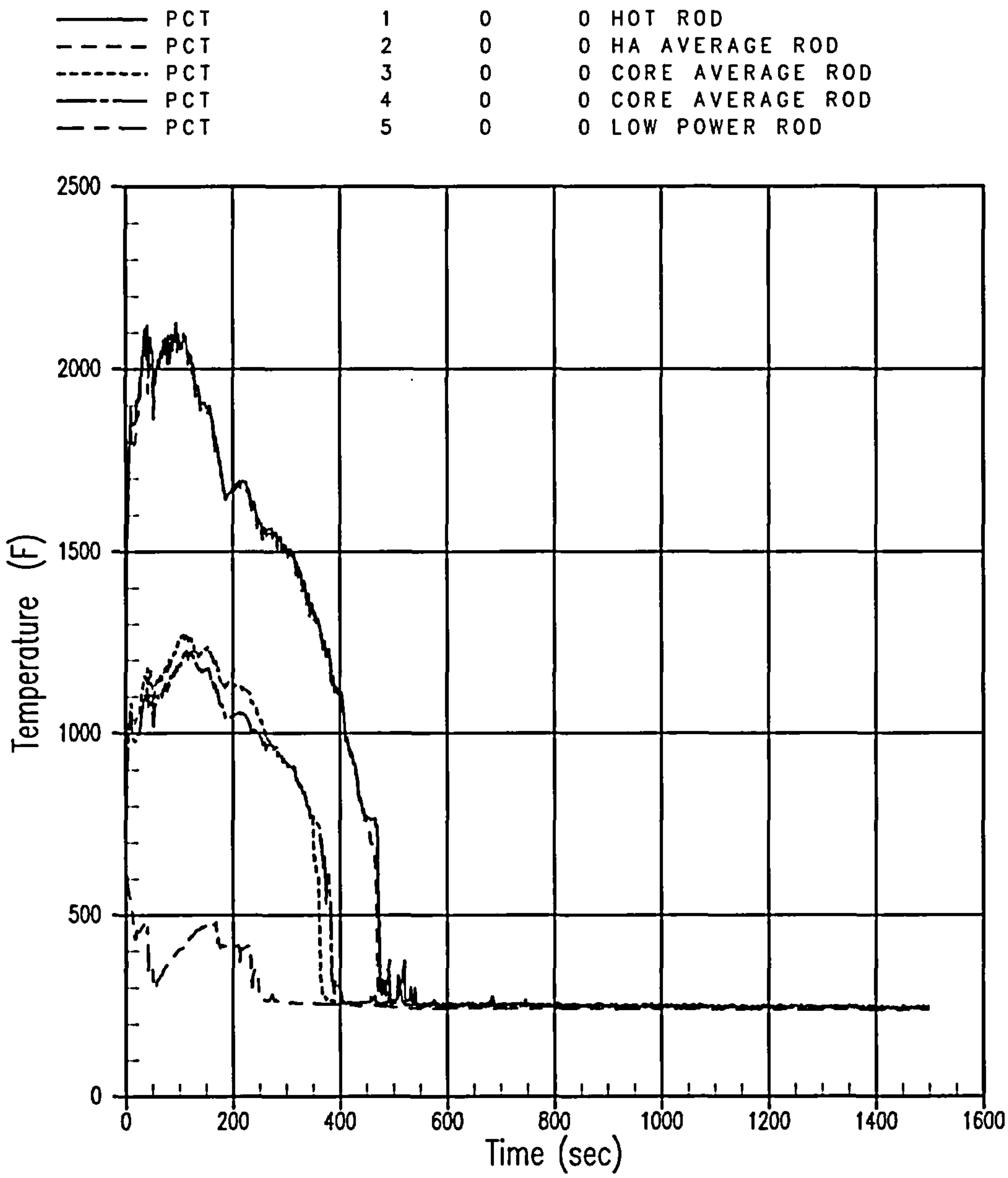

Figure 1 - Peak Cladding Temperatures

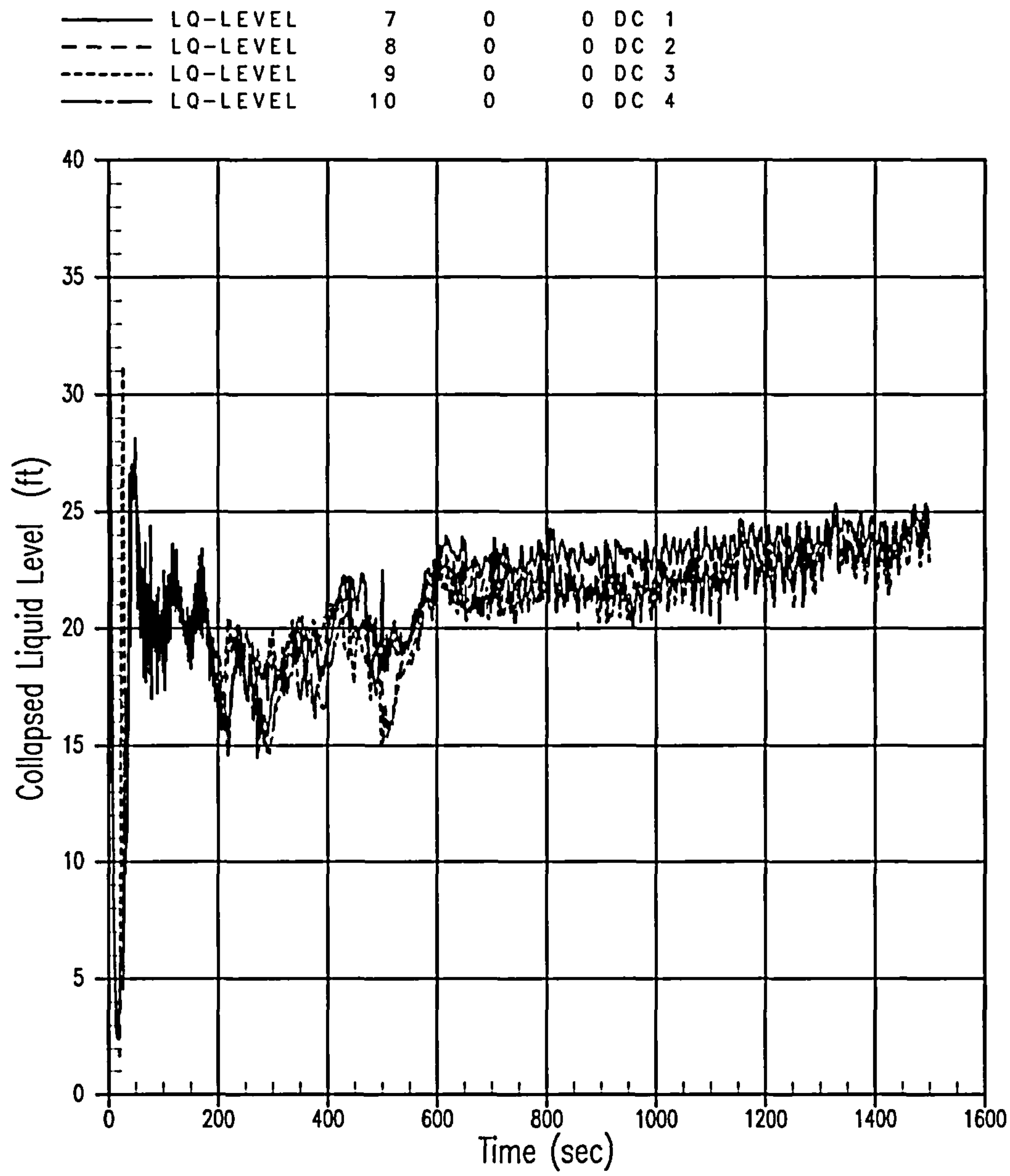

Figure 2 - Downcomer Collapsed Liquid Levels

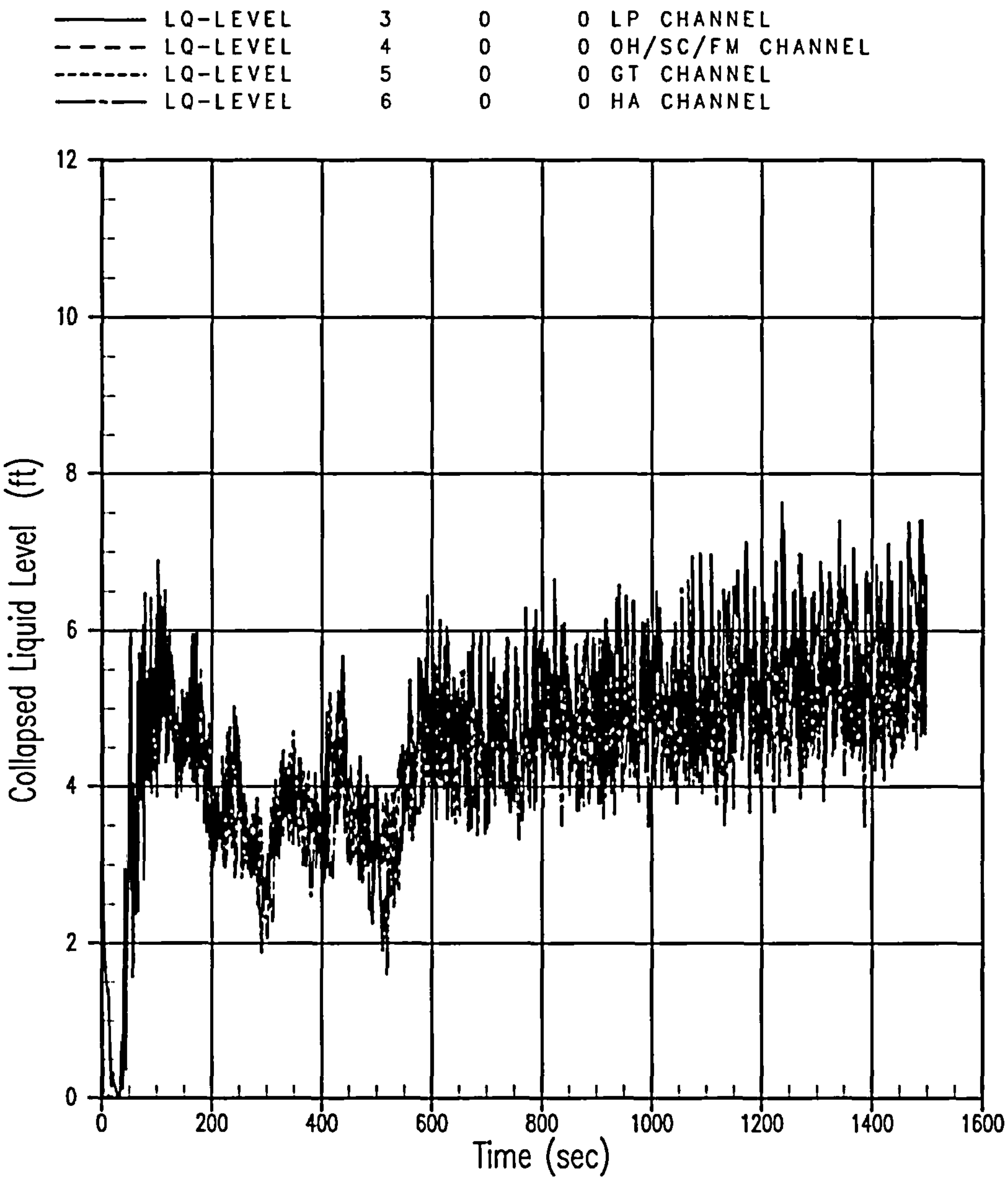

Figure 3 - Core Collapsed Liquid Levels

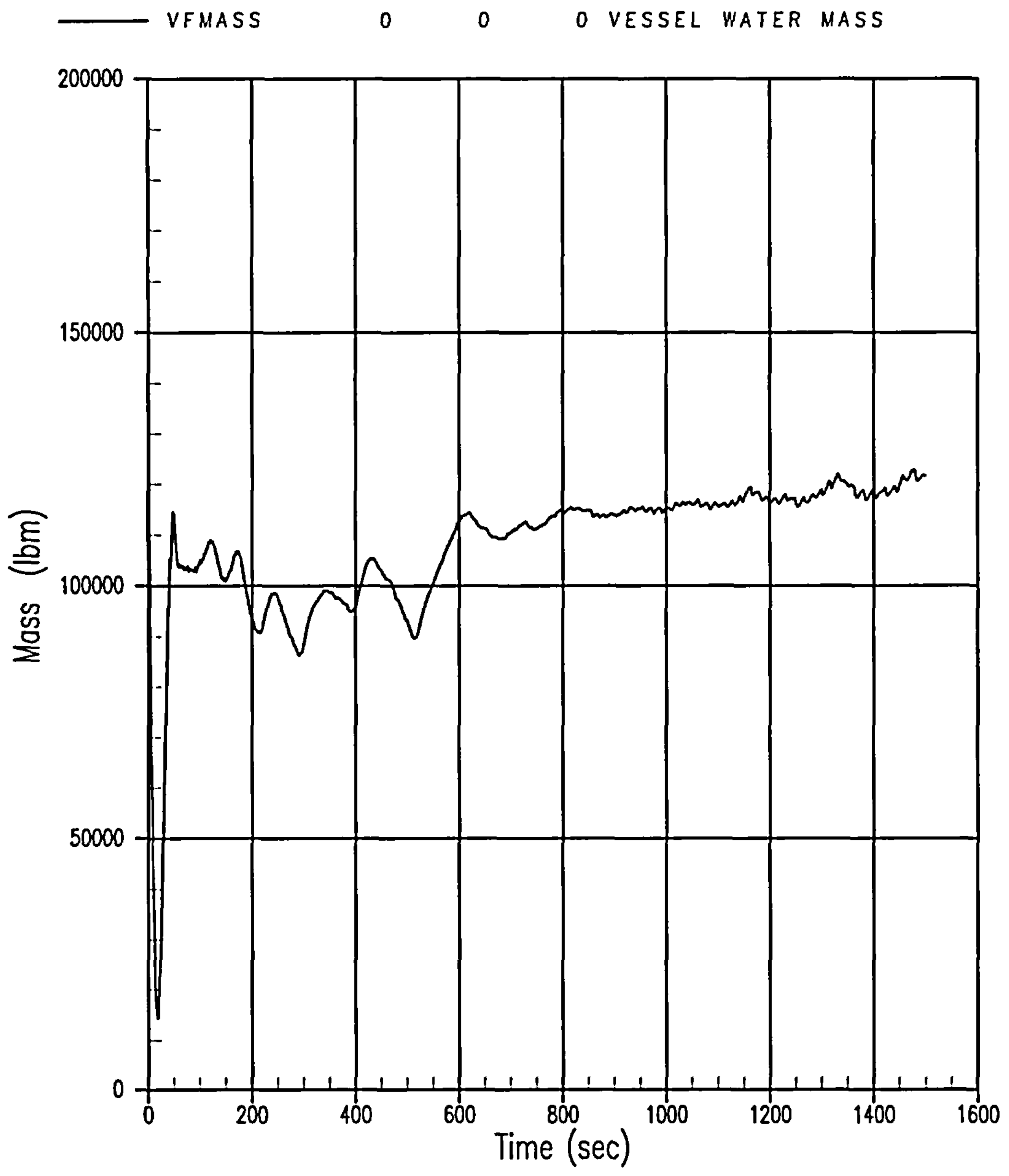

Figure 4 - Vessel Liquid Mass