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Fred Dacimo
Vice President
License Renewal

NL-09-056

May 1, 2009

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

SUBJECT: Entergy Nuclear Operations Inc.
Indian Point Nuclear Generating Unit Nos. 2 & 3
Docket Nos. 50-247 and 50-286
Reply to Request for Additional Information (RAI) – Open Items Items

REFERENCES: 1. NRC Letter dated April 3, 2009, "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application – Open Items"

Dear Sir or Madam:

Entergy Nuclear Operations, Inc is providing, in Attachment 1, Amendment #7 to the License Renewal Application for Indian Point 2 and Indian Point 3. The additional information requested in the referenced letter pertaining to NRC review of the License Renewal Application for Indian Point 2 and Indian Point 3 is provided in Attachment 2. The additional information provided in this transmittal provides clarifications and additional information to previously submitted information in response to staff questions.

Attachment 3 consists of Revision 8 to the list of regulatory commitments providing clarification on Commitment #11 (ISI program – lubrite sliding supports), Commitment #36 (additional core bore samples for Unit 2), and the addition of Commitment #39 (installation of fire suppression system in Unit 2 Auxiliary Feedwater Pump Room).

If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-734-6710.

A001
NRR

I declare under penalty of perjury that the foregoing is true and correct. Executed on
May 1, 2009

Sincerely,

FRD/dmt

Attachment:
1. License Renewal Application Amendment #7
2. IPEC RAI Clarification
3. IPEC Commitment List, Revision 8

cc: Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. Sherwin E. Turk, NRC Office of General Counsel, Special Counsel
Mr. Kenneth Chang, NRC Branch Chief, Engineering Review Branch I
Mr. John Boska, NRR Senior Project Manager
Mr. Paul Eddy, New York State Department of Public Service
NRC Resident Inspector's Office
Mr. Robert Callender, Vice President NYSERDA

ATTACHMENT 1 TO NL-09-056

LICENSE RENEWAL APPLICATION AMENDMENT #7

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL APPLICATION AMENDMENT REQUEST FOR ADDITIONAL INFORMATION – OPEN ITEMS

Follow-up RAI 1: Open Item 3.0.3.2.15-1 (Audit Question 359)
In Entergy Nuclear Operations, Inc. (Entergy) letter NL-08-169, dated November 6, 2008, "Additional Information Regarding License Renewal Application-Operating Experience Clarification," the applicant submitted a supplemental "clarification" describing its plan for implementing a permanent remediation of the Indian Point Nuclear Generating Unit No. 2 (IP2) refueling cavity leakage over the next three scheduled IP2 re-fueling outages (2010, 2012, 2014). In order to complete its review, the staff requests the following information:

a. In order for the staff to address the adequacy of the applicant's proposed monitoring method, the applicant is requested to provide additional information on the leakage path from the refueling cavity to the collection point lower in containment, as well as the leak flow-rate. In this regard, describe the leakage path and chemical composition of the leaking fluid, provide historical flow-rate values, and confirm whether or not any leakage enters the reactor cavity inside the primary shield wall. Provide the technical basis as to how the leakage path was determined, with a focus on water entering the reactor cavity. Provide a sketch of containment and the refueling cavity which highlights the leakage path.

Response for Follow-up RAI 1 (a):

During the first refueling outage in 1976, leakage from the refueling cavity was observed coming from the reactor cavity. The original designed temporary seal between the reactor vessel flange and the reactor cavity was not leak tight. The leakage collected in the reactor cavity pit sump and was pumped out. A plant modification was initiated to use a new design seal, which resolved the problem. Leakage also occurred in the reactor vessel inlet and outlet blow out plugs and instrumentation wireways. Leakage through these paths has been minimized by improving sealing methods.

The leakages from the above sources were not from behind the reactor cavity liner and through concrete construction joints.

In 1993, it was determined that leakage from the refueling cavity was coming through the liner plates. This event initiated detailed investigations and corrective actions to stop the leakage. Unfortunately, the sealing methods have not fully resolved the leakage.

The suspect leakage path was determined by visual observation during and after filling the refueling cavity with water. Leakage is observed as the cavity is filled for refueling operations. Leakage starts as the cavity level reaches the 80 ft. elevation which is approximately 50% cavity level. Leakage was observed initially from three significant areas associated with refueling cavity construction (See Figure 1). Leakage from the refueling cavity collects in a drainage trench on the 46 ft elevation of containment inside the crane wall from where it flows to the containment sump.

A small portion of the leakage from the refueling cavity enters the reactor cavity flowing down the interior primary shield walls to a sump located in the reactor cavity from where it is pumped to the containment sump. Leakage inside the reactor cavity has been primarily attributed to non-liner leakage associated with reactor cavity seal and nozzle inspection box cover isolation issues.

The leaking fluid from the refueling cavity is mixed reactor coolant and refueling water storage tank water with total estimated flow rates on the order of 3 to 7 gpm. No samples of the fluid flowing from the leaking areas have been analyzed for chemical composition. *There has been no degradation of containment structural surfaces from this wetting as observed in the Structures Monitoring Program. Figures 1 through 4 are sketches of the containment area and the refueling cavity which show the locations of the observed leakage.*

b. The transmittal letter NL-08-169, dated November 6, 2008, states: "There are no new commitments identified in this submittal." The applicant has previously taken a bore sample in the region of the leak, and has committed to take another sample prior to entering the period of extended operation. In absence of a formal commitment to remedy the source of leakage, the applicant's aging management program (AMP) should include a method to monitor for a degrading condition in the refueling cavity, and other structures and components that would be affected by the leakage, during the period of extended operation, or the applicant should explain how the structures monitoring program will adequately manage potential aging of this region during the period of extended operation.

Response for Follow-up RAI 1 (b):

As previously described in IPEC Letter NL-08-127 dated August 14, 2008, Audit Question 359, the refueling cavity is a robust structure, with thick walls and low stress levels when compared to the total structural capacity. Exposure to borated water has not resulted in identified degradation or reduction of structural integrity. Industry and IPEC operating experience for the past years has shown that concrete is not significantly affected by exposure to borated water. The refueling cavity is wet during the limited duration (approximately 14 days) when it is filled and is dry during the subsequent period (approximately 24 months) of normal power operations. Moisture remaining following draining of the cavity would be dried up by the ambient temperatures resulting from reactor operation, thus long-term exposure to borated water that could cause significant degradation of the concrete and embedded reinforcement is not expected.

The method to monitor for a degrading condition in the refueling cavity is routine visual inspection of accessible concrete surfaces under the Structures Monitoring Program accompanied by an inspection of concrete that has been exposed to the intermittent borated water leakage for an extended period. The inspection is required by the formal commitment to do core bore samples in the upcoming outage in 2010 for concrete that has been exposed to the leaking borated water on an intermittent basis for much of the life of the plant. If leakage occurs during the upcoming outage, IPEC will obtain a sample of leaking water at an exit point below the cavity and evaluate it for fluid composition.

The results of the sample analysis will be evaluated to establish whether additional aging management activity is necessary during the period of extended operation. Additionally core bore samples will be taken, if leakage is not stopped prior to the end of the first ten years of the period of extended operation (Reference Commitment #36). Other structures and components that could be affected by the leakage that are not addressed under the Structures Monitoring Program would be evaluated under the Boric Acid Corrosion Program. As previously committed to in IPEC Letter NL-08-127, dated August 14, 2008, inspections and activities related to the identification of leakage in the refueling cavity and its impact on the surrounding concrete will provide reasonable assurance that the associated structures will remain capable of fulfilling their license renewal intended functions. The established site operating experience review program ensures that any subsequent new industry or IPEC operating experience will be incorporated to ensure adequate management of potential aging effects of this region during the period of extended operation.

Follow-up RAI 2: Open Item 3.0.3.2.15-2 (Audit Question 360)

In Entergy letter NL-08-169, dated November 6, 2008, the applicant submitted a supplemental "clarification" for the IP2 spent fuel pool pit walls, which provides a detailed description of (1) the design margins for the spent fuel pool concrete walls; and (2) the results of prior concrete core sample testing and rebar corrosion testing.

a. In Commitment 25, the applicant commits to sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least every three months to assess for potential indications of spent fuel pool leakage. This commitment does not describe what actions will be taken if leakage continues. If sampling indicates continued leakage, the applicant's AMP should include a method to determine if a degraded condition exists during the period of extended operation, or the applicant should explain how the Structures Monitoring Program will adequately manage potential aging of the inaccessible concrete of the IP2 spent fuel pool due to borated water leakage during the period of extended operation.

Response for Follow-up RAI 2 (a):

As indicated in Entergy letter NL-08-127, dated August 14, 2008, Audit Question 360, degradation has not been attributed to the effects of aging, but to poor construction and workmanship practices during initial construction activities. Consequently, future degraded conditions are not expected.

The method to determine if a degraded condition exists during the period of extended operation is continued monitoring for leakage by monitoring SFP level and monitoring ground water in the vicinity of the pool exterior walls for indications of pool leakage. The absence of leakage will indicate no degraded condition exists. Leakage, if any, indicates potential degradation. If leakage is found, it will be evaluated under the corrective action program (i.e., Element 7 of the SMP). If sampling indicates that ground water contains constituents indicating pool leakage then evaluation is required under the corrective action program to assess the potential for degradation and determine appropriate corrective actions. An example of the aggressive corrective actions expected in response to identified leakage is found in the condition report described in response to

Audit Question 360, Entergy Letter NL-08-127, dated August 14, 2008. Corrective actions for that condition included inspections of all accessible surfaces of the SFP liner, installation of monitoring wells in the vicinity, performance of UT examinations, bore samples, rebar inspections and inspections using remote camera technology.

As stated in the Statement of Consideration (SOC) for the license renewal rule, "Given the Commission's ongoing obligation to oversee the safety and security of operating reactors, issues that are relevant to current plant operation will be addressed by the existing regulatory process within the present license term rather than deferred until the time of license renewal." Since the issue of SFP leakage is currently being addressed by the existing licensing and regulatory process, that process provides reasonable assurance that appropriate corrective actions will be taken during the current license term. Those actions will continue as appropriate through the period of extended operation.

b. The second paragraph on page 2 of Attachment 1 of the clarification letter dated November 6, 2008, states in part: "[l]ittle or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and low boron concentration indicating that rainwater was the primary cause of the observed corrosion." The staff requests the applicant to identify any Unit 2 and Unit 3 operating experience related to rebar corrosion, in light of the chloride content in rainwater, and identify the likely source for the high chloride content in the rainwater. Additionally, the applicant is requested to explain whether and how the AMP is adequate to address this environment and the related potential aging effects to ensure there is no loss of intended function during the period of extended operation.

Response for Follow-up RAI 2 (b):

The original 1993 consultant analysis associated with the degraded concrete area speculated that the likely source for the high chloride content was condensation of chloride laden air (chlorides from the brackish Hudson River water) on the outer surface of the pool wall. It has since been concluded that the chloride source was likely associated with the use of rock salt or storage of chemicals or materials in the area. Studies of the chloride content in rain water and ground water do not support the levels that were found in 1993. Studies typically show the national average of chlorides in rain water to be a maximum of 1.0 to 1.5 parts per million (PPM) with values inland approaching 0.2 PPM. The National Atmospheric Deposition Program (NAPD), Hudson Valley location West Point station, located upriver from the plant, chloride data from 1983 to 2007 shows values from 0.18 to 0.66 PPM. This is significantly lower than the values initially reported and does not support the supposition that chlorides originated from rainwater. No IP operating experience has linked high chlorides in rainwater to corrosion of embedded rebar. The pool wall was repaired eliminating the spent fuel pool rebar exposure to rainwater.

The aging management programs for concrete exposed to the elements, the Structures Monitoring Program and the Containment ISI Program, are adequate to address this

environment and the related potential aging effects to ensure there is no loss of intended function during the period of extended operation. Visual inspections performed under these programs have confirmed no loss of intended function due to aging effects. These programs will continue to monitor potential future degradation of the concrete cover that could result in exposure of the underlying rebar to the outdoor environment.
Minor degradation that has been observed during these inspections has shown little change between inspections confirming the adequacy of the inspection frequency of the Structures Monitoring and Containment ISI Programs. If rebar degradation is identified during future inspections (e.g., observation of concrete staining during visual inspection), the condition will be evaluated in accordance with the program requirements to ensure necessary corrective actions are taken to prevent loss of intended function.

Follow-up RAI 3: Open Item 3.0.3.3.2-1 (Audit Question 361)
In Entergy letter NL-08-169, dated November 6, 2008, the applicant submitted a supplemental "clarification" for Indian Point (IP) containment spalling, describing the design margins for the IP containment structures at the locations of existing concrete degradation. Based on its review of the information, the staff identified areas that need further clarification and/or additional information to complete its review as described below:

a. The clarification for the IP containment spalling states: "As the surface concrete is not credited for tensile strength of the structure, the spalling has no impact on the available margins." The strength margins identified appear to be based on the nominal rebar dimensions, without any consideration for rebar degradation due to exposure and potential loss of bond between the concrete and the rebar. Explain how the existing degradation and design margin will be considered in performing periodic inspections to monitor degradation that would ensure that there is no loss of containment intended function during the period of extended operation.

Response for Follow-up RAI 3 (a):

As stated in Letter NL-08-169, dated November 6, 2008, the existing surface concrete degradation and potential loss of bond between the concrete and the rebar has no impact on the ability of containment to perform its intended function during the period of extended operation. The design margins in containment are such that loss of one bar in every 4.5 feet in the vertical direction would not impact the ability of containment to perform its intended function. The ISI-IWL inspections have confirmed that there has been no identified degradation that could result in loss of function of the containment structure (rebar and concrete) due to aging effects. Localized surface rust has been observed at containment areas where rebar has been exposed, but these visual inspection results show no discernable deviation of rebar dimensions from nominal. No degradation has been observed that indicates loss of bond for rebar that is not monitored directly.

As part of the IPEC corrective action program (i.e., program Element 7), if degradation is identified during inspections, the impact of the degradation on design margin will be evaluated to ensure that there has been no loss of containment intended function. Evaluations performed on containment associated with potentially degraded rebar (i.e., *localized surface degradation) have shown that loss of a number of reinforcing bars would have an insignificant effect on containment stress margins and would not impact containment intended function. Degradation of the rebar will be readily discernable as obvious changes in bar dimensions well before such degradation could progress to the point of challenging the available design margins.*

b. In the spent fuel pool discussion, in the letter dated November 6, 2008, the applicant stated: "[l]ittle or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and low boron concentration indicating that rainwater was the primary cause of the observed corrosion." The applicant is requested to provide the technical basis for the adequacy of the 5-year IWL frequency of inspection of the degraded areas of the IP containments during the period of extended operation, considering the possibility of an increased site-specific corrosion rate of the exposed rebar on the containments. This should include results of prior inspections, including any available comparative photos showing the progression of degradation.

Response for Follow-up RAI 3 (b):

The technical adequacy of the 5-year IWL frequency of inspection of the degraded areas of the IPEC containments has been demonstrated by past inspection results. No detectable changes have occurred over the 5-year period between past inspections. The rate of degradation of the exposed rebar of the containments has been imperceptible. Documented inspection history for the first period IWL inspection began in 1999. Photographs taken of exposed rebar in the most recent inspection in 2009 were compared to photographs taken during the first IWL interval inspection in 2000 and a subsequent inspection in 2005. As can be seen from the photos in Figures 5 through 7 corrosion of the exposed rebar is almost nonexistent with no noticeable change in appearance over the years. Spalling is confined to a small area around the rebar with no noticeable cracking being present, which would indicate that the degradation is localized or has not progressed along the length of the rebar creating the potential for more spalling. Therefore, based upon past and recent inspection, increased corrosion rates have not been identified and additional degradation, which could prevent the containment from performing its intended function, would be readily detected by the established IWL inspections.

Follow-up RAI 4: Open Item 3.5-1

In Entergy letter NL-08-169, dated November 6, 2008, the applicant submitted a supplemental "clarification" to license renewal application (LRA) Section 3.5.2.2 related to the concrete mix design method and the durability of concrete used at IP. In the LRA the applicant claimed that concrete meets the specifications of ACI 318-63 and the intent of ACI 201.2R-77, Guide to Durable Concrete. As a result the applicant claimed that several aging effects were not applicable to concrete. Based on its review of the information, the staff identified areas that need further clarification and/or additional information to determine that the applicant meets the cited ACI specifications such that further evaluation is not necessary as recommended by the GALL Report.

a. In the clarification to LRA Section 3.5.2.2 (Part 1) on page 6 of Attachment 1 to letter NL-08-169, the applicant stated that it used Method 2 of Section 502 of ACI 318-63 by testing trial mixes to determine the water-cement ratios for the concrete mix design of the IP containments and other structures. In order for the staff to evaluate the quality and durability of concrete in IP structures that may be subject to degradation during the period of extended operation, the staff requests the applicant to define the water-cement ratio that was used at the time of construction. Additionally, to assist the staff in understanding the parameters related to concrete strength and durability during the period of extended operation, the applicant is requested to describe the methodology used to establish the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318-63, Method 2. The applicant is requested to provide a summary of the results of statistical analyses performed, if any, of the original concrete strength tests, including number of samples, raw strength values from the test, the mean, the standard deviation, and the original criterion (e.g., mean minus 1 standard deviation, coefficient of variation) used to confirm that the required compressive strength was achieved. The applicant is requested to provide this information for the IP containments and other safety-related IP Unit 2 and 3 concrete structures, including the refueling cavities and the spent fuel pools, to support the applicant's view that IP concrete meets the requirements of Method 2 in Section 502 of ACI 318-63 and the intent of ACI 201.2R-77.

Response for Follow-up RAI 4 (a):

Pour data samples taken during construction show water-to-cement ratio used at IPEC ranged from a low of 0.488 (equipment hatch area) to a high of 0.611 (containment el. 68') with an average ratio at the time of construction of 0.534. The method used to confirm the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318-63, Method 2 is testing of actual field samples taken during construction. ACI documents state that strength and durability are primarily governed by water-to-cement (w/c) ratio, and strength goes hand-in-hand with durability. The strength and durability are both based on the permeability of the concrete which is based on the distance between the cement particles, i.e. the closer the cement particles the stronger the concrete. Permeability is therefore a function of the w/c ratio, particle size distribution (PSD), type of cement, type of aggregate, compaction and quality control. Relying on just one indicator for durability is not justified, which is why the ACI code uses it only as a first estimate based on the tables for determining strength and durability. The ACI documents recommend that the strength based on w/c ratio should be verified by trial batches to ensure the specified properties of the concrete are met. To confirm that the required compressive strength was achieved, ACI 214.3R-88, "Simplified Version of the Recommended Practice for Evaluation of Strength Test Results of Concrete" was used to develop a summary of the results of the original concrete strength tests. These results are based on raw strength values from the test samples to obtain the mean and the standard deviation.

IPEC containment and other safety-related structures were designed for a minimum compressive strength of 3000 psi. A total pour of approximately 20,000 cubic yards was expected. Therefore, in order to ensure this design parameter was achieved, an average design margin of 15% above this minimum was also specified.

Approximately 200 concrete test reports for concrete used in IP containment, refueling cavity and spent fuel pool area were reviewed. Air entrainment values ranged between 3.5 and 6.5%. Only a few of the test reports indicated air entrainment higher than 6.0%. Those values are acceptable based on the ACI 211.1-77 section 5.3.3 which shows that higher entrainment values up to 7% are acceptable for extreme exposure conditions, higher air entrainment is generally better for durability. A primary concern for high air entrainment is an accompanying reduction in concrete strength. As discussed in the following paragraph, the concrete used for IP containment, refueling cavity and spent fuel pool still exceeded the concrete design strength requirements in accordance with ACI 318-63 producing durable, low permeability concrete.

Each concrete test report involved an average of 3 sample concrete cylinders for strength testing. No test cylinder strength under 3000 psi 28-day strength was observed. The compressive strength from these samples ranged from a low of 3436 psi (containment exterior wall el. 68'-73') to 5393 psi (containment ring area) with an extreme of 6410 psi (containment equipment hatch area). The standard deviation obtained from the samples reviewed was determined to be approximately 670 psi with an average or mean concrete compressive strength of approximately 4050 psi. Based on this actual concrete test data, the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318-63, Method 2 was achieved with no sample below one standard deviation from the mean. Although this identifies that IPEC concrete is of good quality, the credited programs in Appendix B of the application will confirm the absence of significant concrete aging effects.

b. If the applicant is unable to provide the information requested in part (a) above, the applicant is requested to explain how the aging effects on concrete will be adequately managed and safety margins will be determined during the period of extended operation.

Response for Follow-up RAI 4 (b):

No response required. The information requested in part (a) has been provided.

Follow-up RAI 5: Open Item 3.5-2

In Entergy letter NL-08-169, dated November 6, 2008, "Additional Information Regarding License Renewal Application-Operating Experience Clarification," the applicant submitted a supplemental "clarification" to LRA Section 3.5.2.2 (Part 3) for IP2 containment concrete and its ability to withstand local area temperatures up to 250ºF. The staff has identified areas that need further clarification and/or additional information as discussed below:

a. Clearly explain the role of the air-to-air heat exchangers in cooling the concrete around the hot piping penetrations. Include the normal operating temperature of the concrete as well as the maximum concrete temperature assuming failure of the heat exchangers.

Response for Follow-up RAI 5 (a):

The air-to-air heat exchangers are discussed in IPEC 2 & 3 UFSAR Section 5.1.4.2.2 and Section 5.1.4 respectively. The function of the hot penetration cooling (HPC) *system is to provide a cooling medium that will limit the temperature of the containment concrete surrounding a thermally hot penetrating line. Operating procedures require the system to be placed in service whenever RCS temperature is > 150°F.*

The HPC system comprises two separate and non-interconnected subsystems. Each subsystem is composed of 2 positive displacement blowers, valves, air-to-air heat exchangers and connecting piping. Each of the subsystems blowers supplies air from outside the building to the air-to-air heat exchanger which cools the space between the process line insulation and the penetration sleeve. The air-to-air heat exchanger is made by welding together one flat sheet on one embossed sheet of 10-gauge carbon steel. The embossment forms the coolant channels, through which the HPC system air passes. The unit is rolled into the form of a cylinder with an outside diameter of the penetration sleeve and inside diameter that allows placement over the outside of the pipe insulation (See Figures 8 and 9). A typical hot penetration detail is shown in IP2 and 3 UFSAR Fig 5.1-30 and 5.1-12 respectively.

There is one subsystem with two blowers for the main steam and feedwater penetrations, and one subsystem with two blowers for the hot penetrations in the radiological controlled area. Only one blower is needed in each subsystem. In the event that the operating blower stops, an alarm is initiated signaling to put the other one in service and initiate corrective actions.

Specific system pressure values have been established, which may indicate a possible obstruction, such as a clogged filter or debris in the system. The operators make daily rounds and would initiate corrective actions if unacceptable pressure values are observed. Corrective actions may include replacement of filters, belts or silencers and blowing out of the heat exchangers, if necessary.

System reliability was assessed by a review of IPEC operating experience over the past nine years of operation of the HPC system. The review identified no instances of loss of cooling which resulted in excess temperatures on concrete. This review identified that four IP2 and nine IP3 condition reports had been initiated. There were none that identified the cause as hot temperature on concrete. Ten were initiated due to vibrations and belt noise and three were due to increased motor temperature.

Temperatures taken in 1994 around the IP2 main steam penetrations over a period of eleven months during normal operations indicate that concrete was exposed to a range of temperatures from a low of 109°F to a high of about 200°F with the highest temperature occurring during the summer months. Based upon design and actual operating experience, recommendations of the NUREG 1801 (GALL) for concrete temperature are satisfied.

Analyses have been performed to characterize the concrete temperature response in the very unlikely event of system failure. To evaluate this scenario, IPEC performed a transient heat transfer analysis of containment hot piping penetrations. The results of the analysis indicated that in the improbable case that all cooling air would be lost to these penetrations, the surrounding concrete temperature at the hottest penetration (main steam piping) would increase by about 80°F in approximately 100 hours. It is highly improbable that cooling air would be lost for as much as 100 hours since the failure of any of the air blower drive motors is alarmed in the control room and operator *daily walk downs would identify system deficiencies. Even if the adjoining concrete did reach temperatures of 250 – 300°F, the strength of the structure would not be impaired for the following reasons.*

1) *No credit was taken for the tensile strength of the concrete around the penetrations.*
2) *These temperatures have substantially no effect on the strength of the penetration sleeve or the reinforcing bar in the area of the penetration.*

b. In the clarification to LRA Section 3.5.2.2 (Part 3) on page 7 of Attachment 1 to letter NL-08-169, the applicant stated that a 15% reduction of concrete strength could be expected when reaching temperatures of 250ºF and that concrete compressive strength tests showed an actual strength more than 15% higher than design strength. Please provide the methodology used to arrive at the conclusion that the actual concrete strength is more than 15% greater than 3000 psi, (i.e., greater than 3450 psi). Provide a summary of the results, including number of samples, raw strength values from the test, the mean, the standard deviation, and the original criterion (e.g., mean minus 1 standard deviation) used to confirm that the claimed strength was achieved. Explain how consideration was given to the reduction in modulus of elasticity in the high temperature concrete evaluation.

Response for Follow-up RAI 5 (b):

The method used to arrive at the conclusion that the actual concrete strength is at least 15% greater than 3000 psi, (i.e., greater than 3450 psi) is review of actual concrete test results. The results of concrete samples taken and tested during construction in accordance with the requirements of ACI provide assurance that the minimum design strength of 3000 psi was achieved. Actual test results show that the containment shell and internal concrete had an average compressive strength of 4050 psi as indicated in Follow-up D-RAI 4: Open Item 3.5-1. No reduction in modulus of elasticity is expected for short term exposure of concrete to temperatures at or below 250°F. Consideration of high temperatures effects on the modulus of elasticity was evaluated during the high temperature concrete evaluation. ,A review of information gathered from industry literature on effects of temperature concluded that concrete does not experience a significant reduction in elastic modulus due to exposure to temperatures less than 300°F. Based on this data, no reduction in strength or modulus of elasticity was determined in the evaluation.

c. If the applicant is unable to provide the information requested above, the applicant is requested to explain how the aging effects on concrete, due to high temperatures, will be adequately managed during the period of extended operation.

Response for Follow-up RAI 5 (c):

No response required. The information requested in parts (a) and (b) has been provided.

General Floor Plan – Containment Bldg.
Elev. 46'–0"

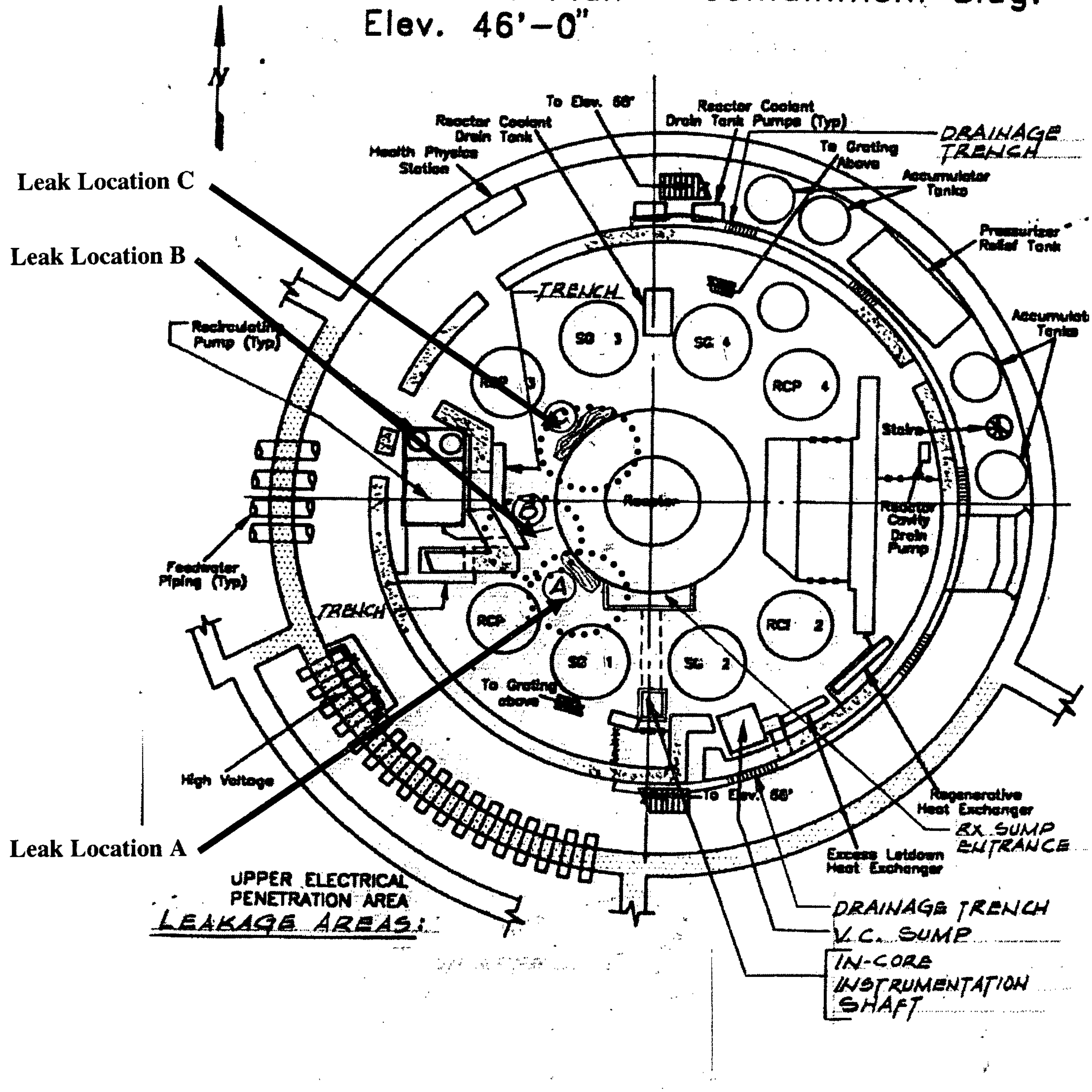


FIGURE 1

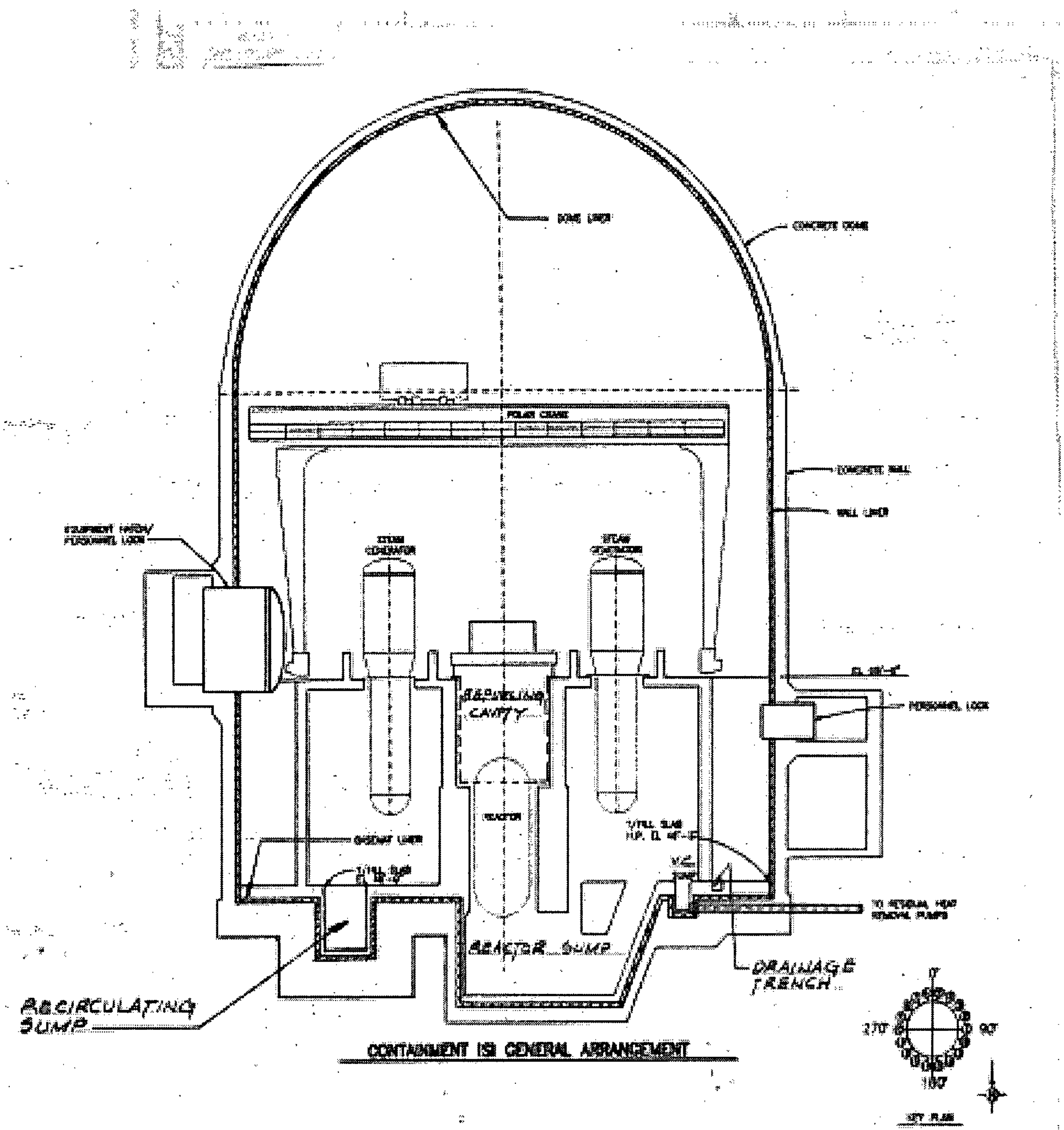

RECIRCULATING SUMP
REACTOR SUMP
DRAINAGE TRENCH
CONTAINMENT ISI GENERAL ARRANGEMENT

FIGURE 2

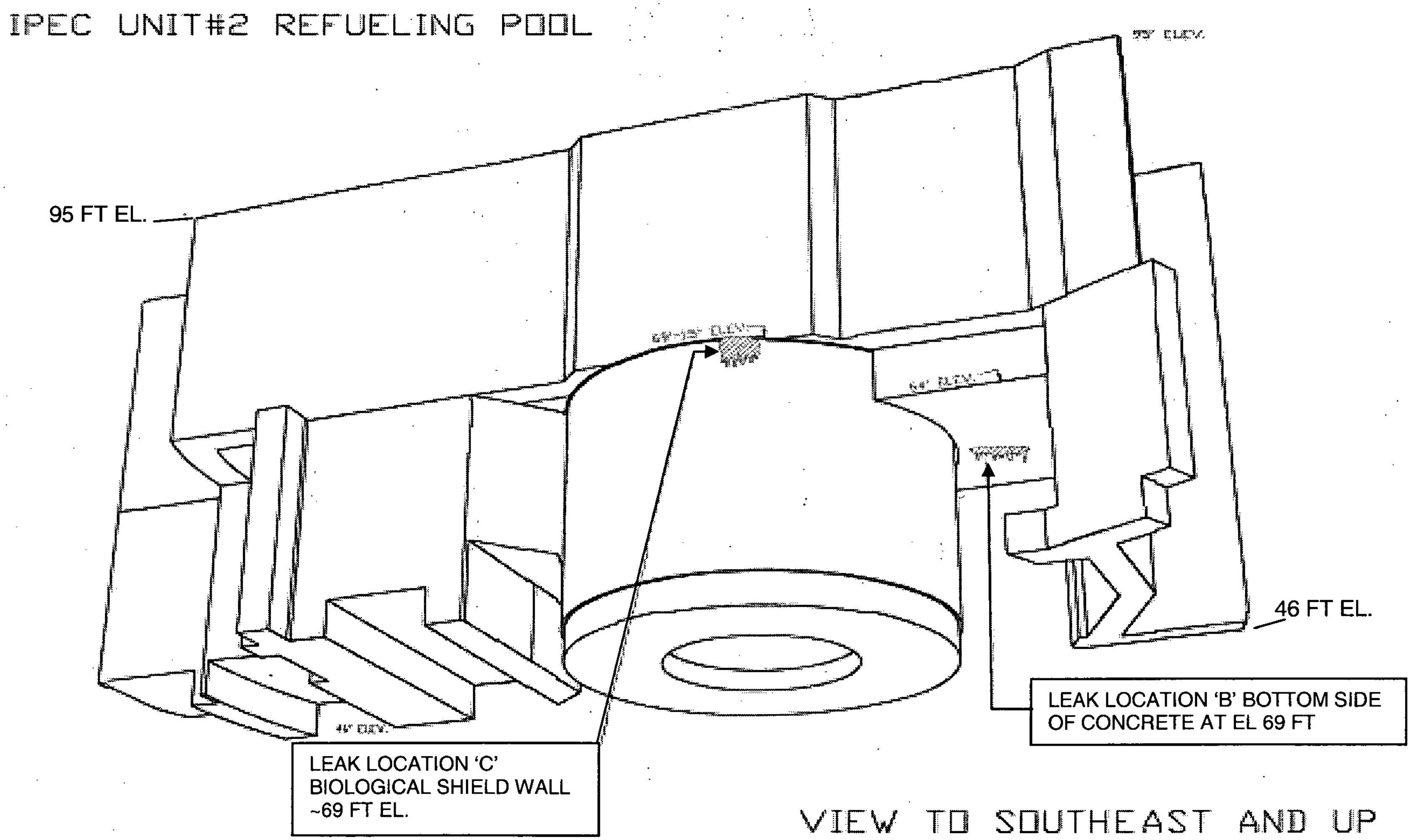

IPEC UNIT#2 REFUELING POOL
95 FT EL.
46 FT EL.
LEAK LOCATION 'B' BOTTOM SIDE OF CONCRETE AT EL 69 FT
LEAK LOCATION 'C' BIOLOGICAL SHIELD WALL ~69 FT EL.
VIEW TO SOUTHEAST AND UP

FIGURE 3

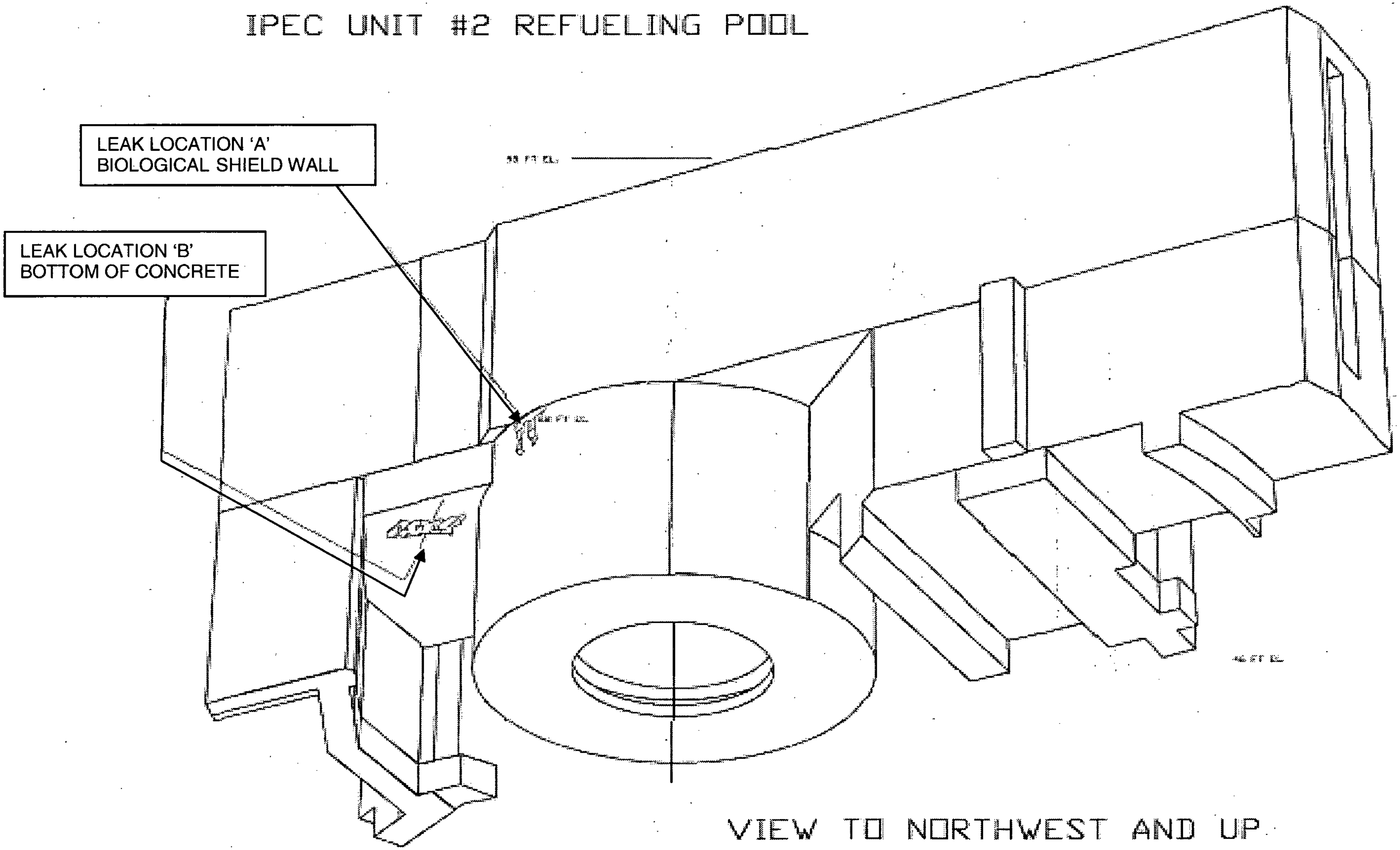
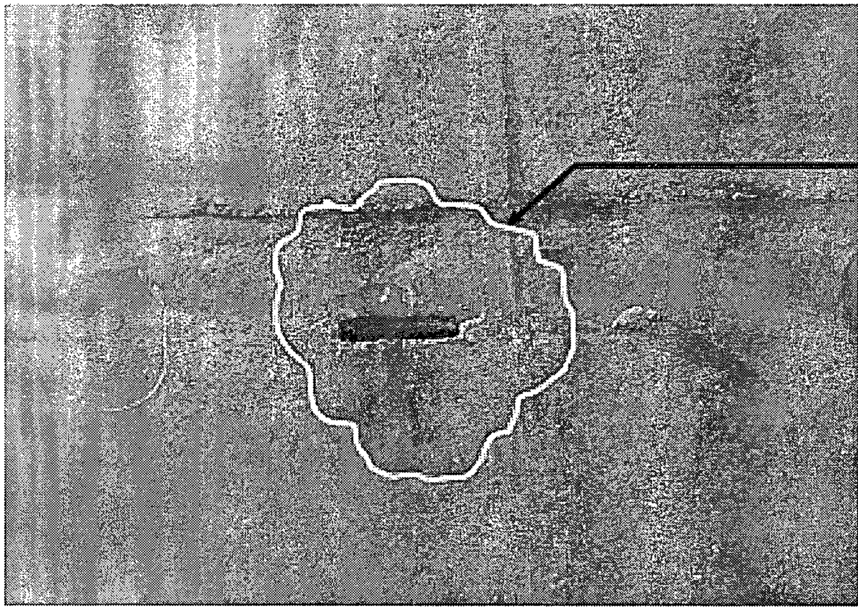
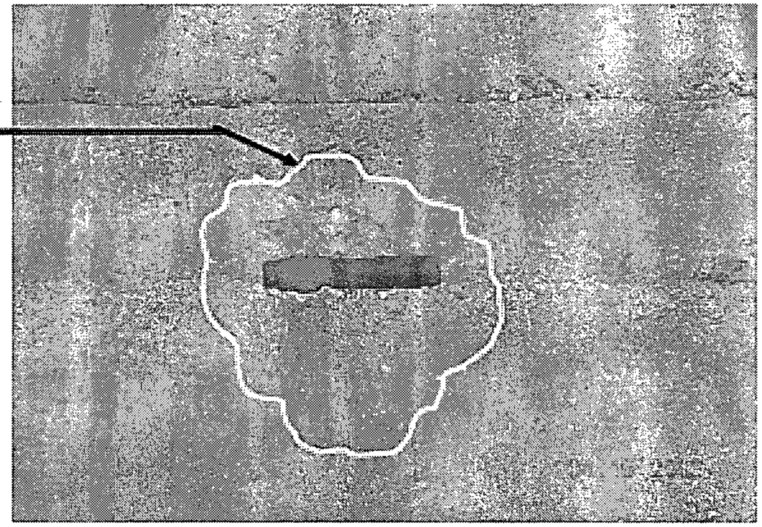

IPEC UNIT #2 REFUELING POOL
LEAK LOCATION 'A'
BIOLOGICAL SHIELD WALL
LEAK LOCATION 'B'
BOTTOM OF CONCRETE
VIEW TO NORTHWEST AND UP

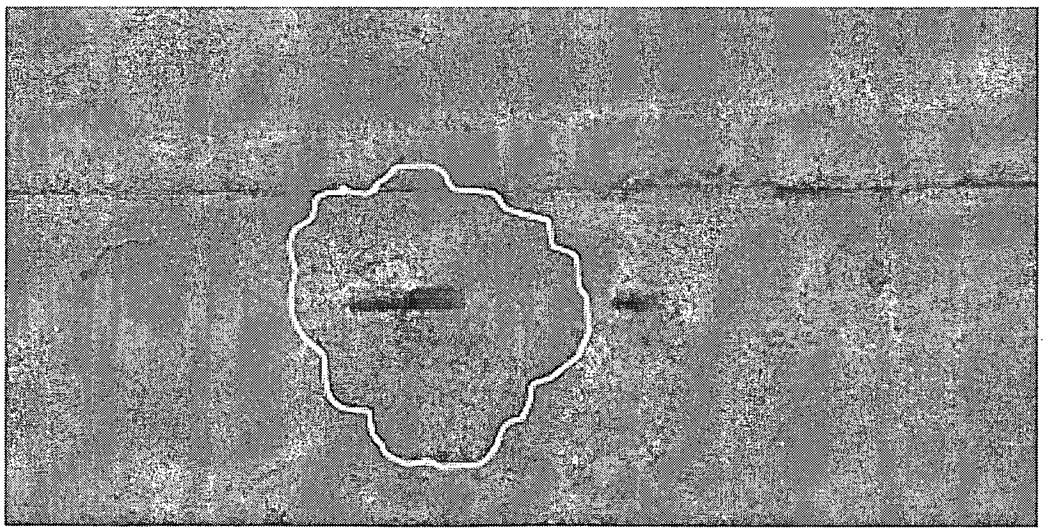
FIGURE 4



2005 IWL Photo



4-15-2009 Photo

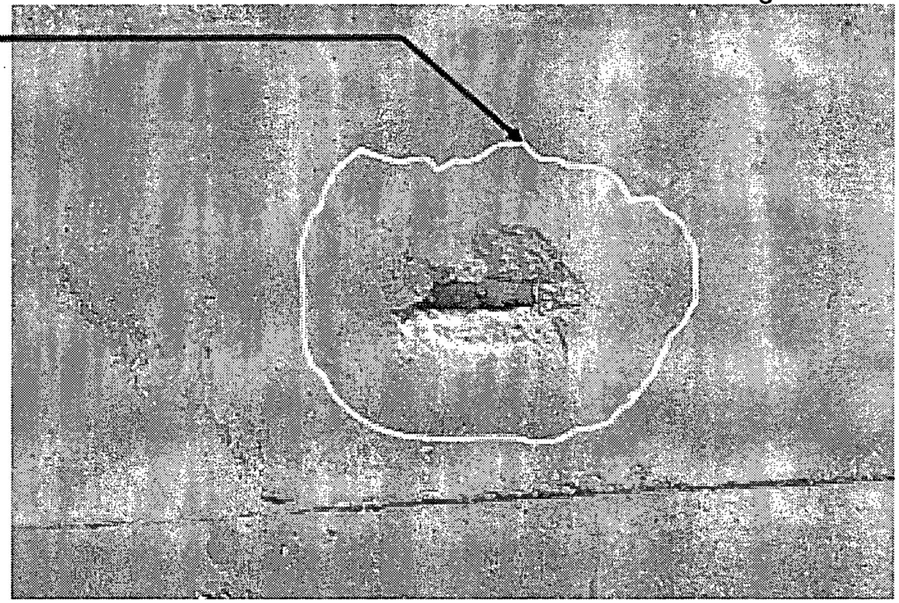


2000 IWL Photo:

2" high by approx. 8" long Cadweld On Cylinder portion of U2 containment.

FIGURE 5

2005 IWL Inspections



4-15-2009 Photo

2000 IWL Photo:

8" diameter popout that fell between 2000 and 2005 inspections. Which exposed the embedded metal piece ~1" x 5" .

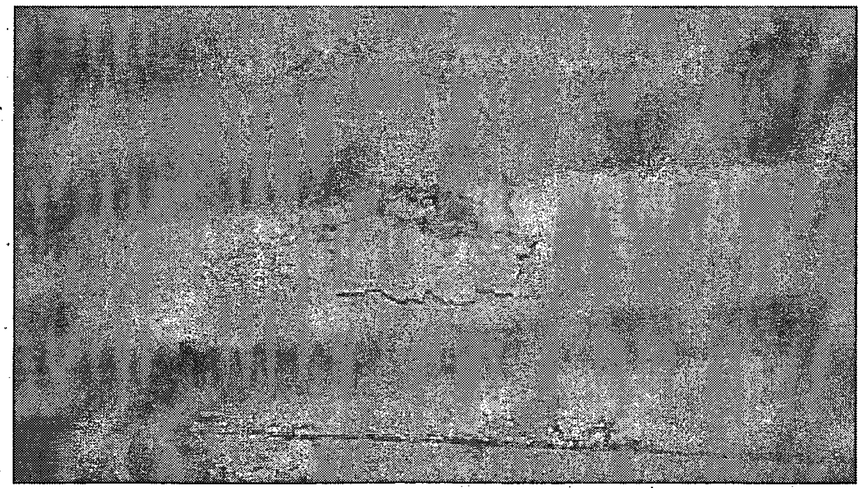
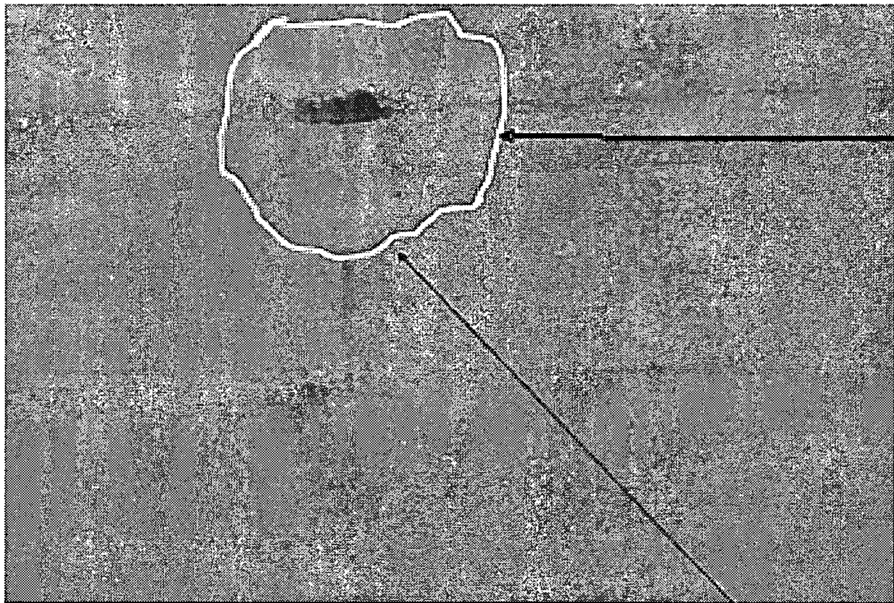
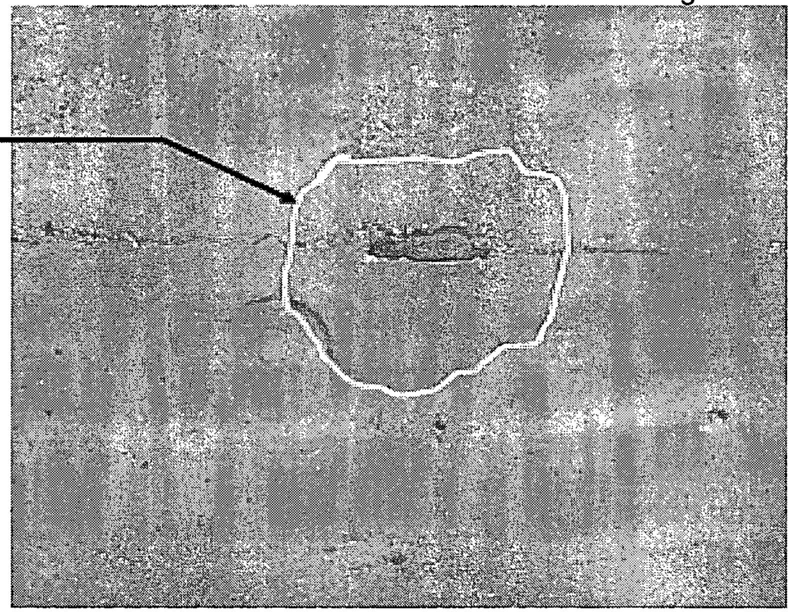


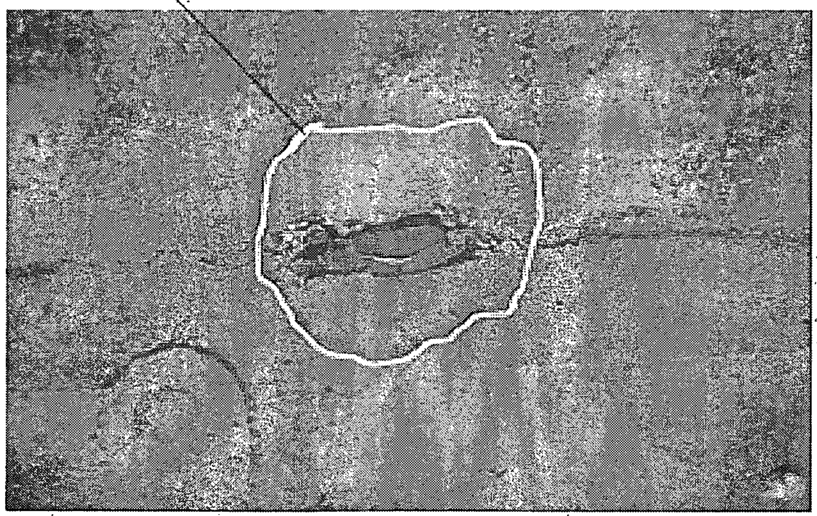
FIGURE 6



2005 IWL Inspections



4-15-2009 Photo



2000 IWL Photo:

~2" x 8" long exposed cadweld.
Note the small concrete patch material fell off between the 2000 and 2005 inspection.
Cosmetic change only

FIGURE 7

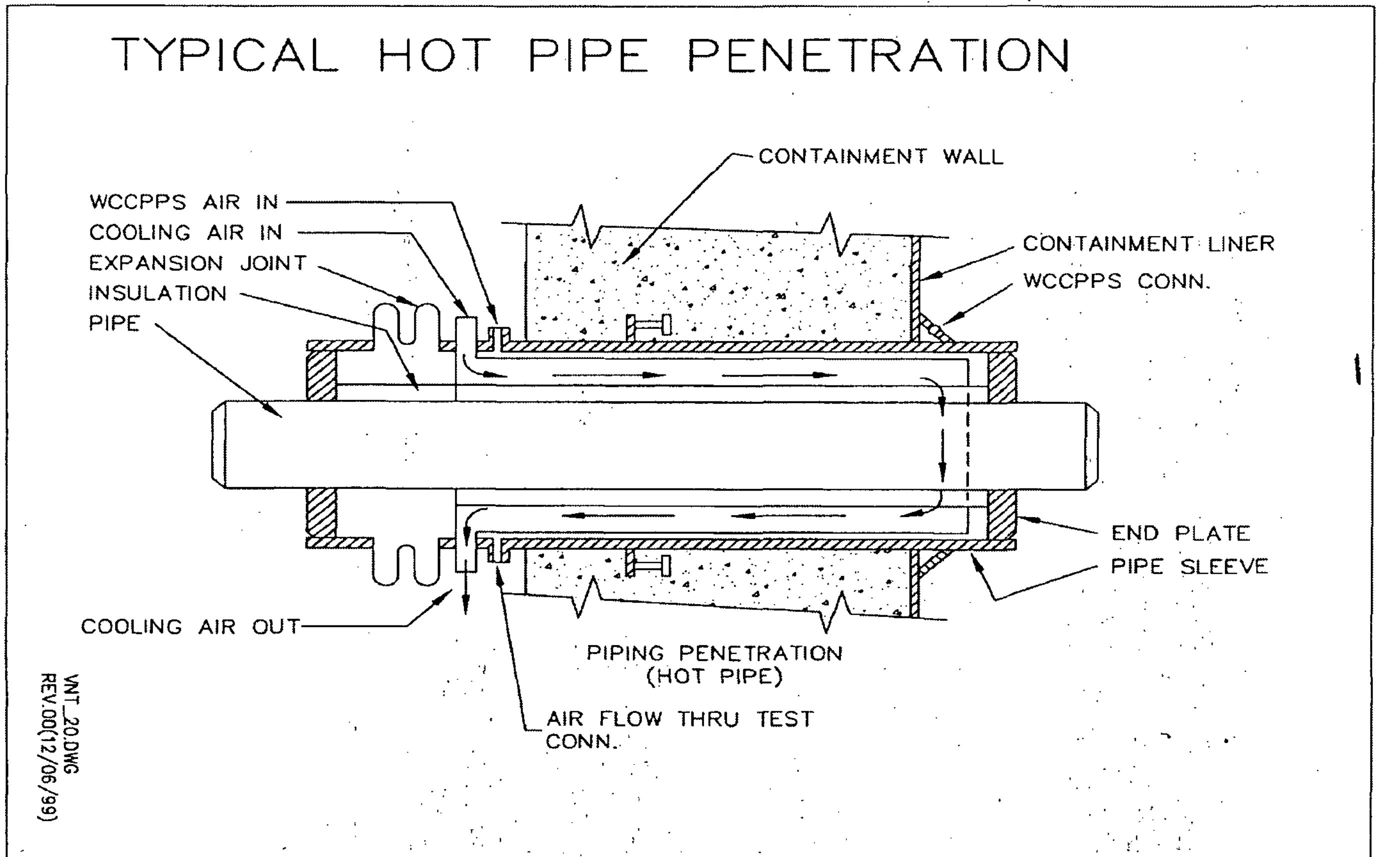

TYPICAL HOT PIPE PENETRATION
CONTAINMENT WALL
WCCPPS AIR IN
COOLING AIR IN
EXPANSION JOINT
INSULATION
PIPE
CONTAINMENT LINER
WCCPPS CONN.
END PLATE
PIPE SLEEVE
COOLING AIR OUT
PIPING PENETRATION
(HOT PIPE)
AIR FLOW THRU TEST
CONN.
VNT_20.DWG
REV.00(12/06/99)

FIGURE 8

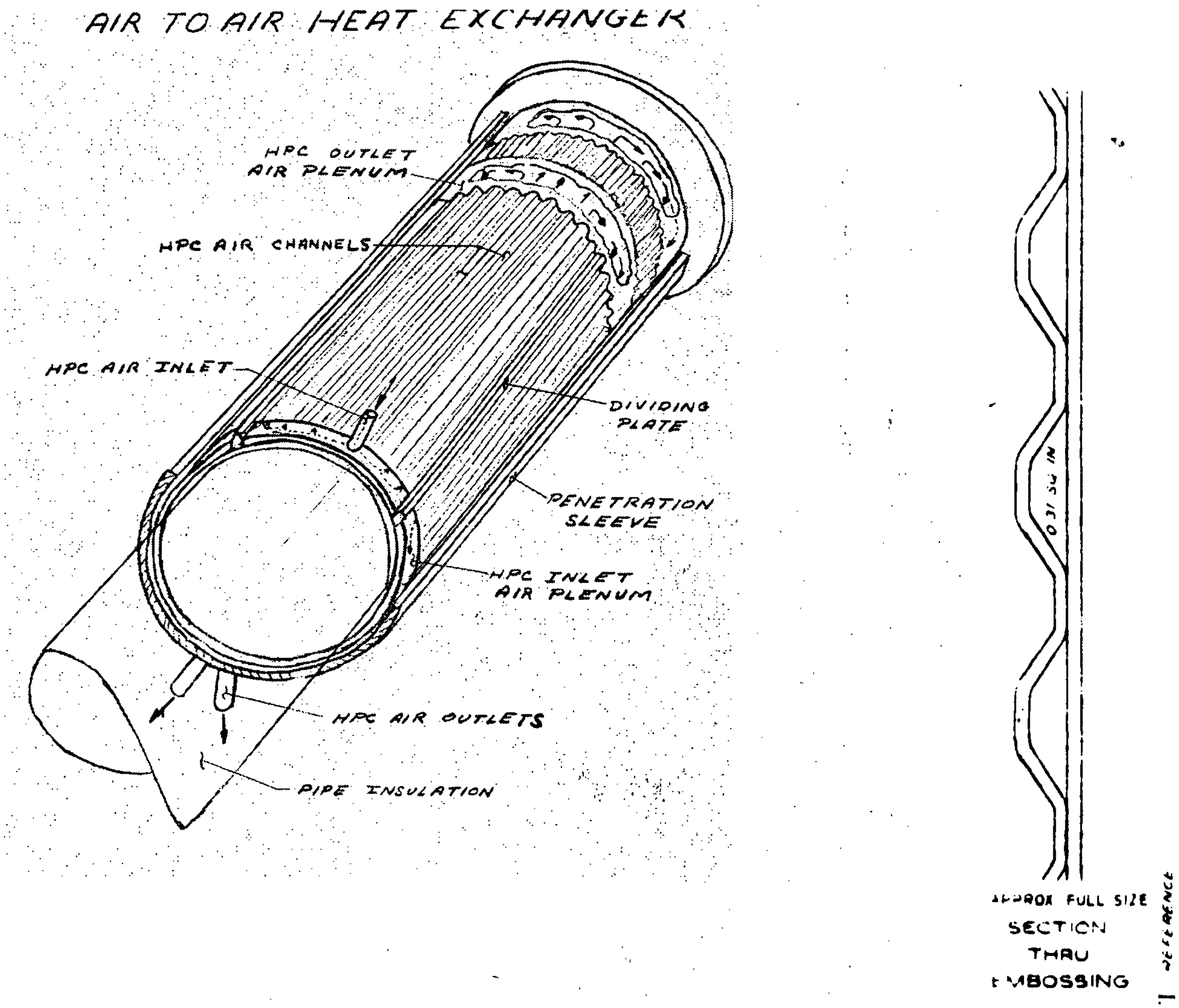

AIR TO AIR HEAT EXCHANGER
HPC OUTLET AIR PLENUM
HPC AIR CHANNELS
HPC AIR INLET
DIVIDING PLATE
PENETRATION SLEEVE
HPC INLET AIR PLENUM
HPC AIR OUTLETS
PIPE INSULATION
APPROX FULL SIZE
SECTION
THRU
EMBOSSING

FIGURE 9

ATTACHMENT 2 TO NL-09-056

IPEC RAI Clarifications

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

**INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION (RAI)
CLARIFICATION**

RAI 3.4.2-1

In LRA Section 3.4.2, the applicant summarizes its AMR results for the IP2 auxiliary feedwater pump room fire event. In the LRA, the applicant states that:
The components in the systems required to supply feedwater to the steam generators during the short duration of the fire event are in service at the time the event occurs or their availability is checked daily. Therefore, integrity of the systems and components required to perform post-fire intended functions for at least one hour is continuously confirmed by normal plant operation. During the event these systems and components must continue to perform their intended functions to supply feedwater to the steam generators for a minimum of one hour.

Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event and corrective action will be required to sustain continued operation. For the minimal one hour period that these systems would be required to provide make up to the steam generators, further aging degradation that would not have been apparent prior to the event is negligible. Therefore, no aging effects are identified, and no Summary of Aging Management Review table is provided.

Section 54.21(a)(1) of 10 CFR requires that for those systems, structures, and components within the scope of license renewal, as delineated in § 54.4, applicants must identify and list those structures and components subject to an aging management review. Additionally, Section 54.21(a)(3), requires that for each structure and component identified in paragraph 54.21(a)(1), applicants must demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation. Based on the information contained in the LRA, Entergy has not demonstrated that the effects of aging for passive, long-lived components within the systems credited for providing flow to the steam generators during the fire event will be adequately managed.

For those systems, or portions thereof, that are identified in response to RAI 2.3.4.5-2, part c, the staff requests that the applicant provide a list of passive, long-lived component types, material, environment, and aging effect combinations, and the programs that will be used to manage the aging effects.

Response for RAI 3.4.2-1

As indicated in LRA section 2.3.4.5, normal plant operation demonstrates the ability of secondary systems to supply feedwater to the steam generators. This includes the systems that function to supply feedwater to the steam generators in the unlikely event of a fire in the AFW pump room. The function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room is confirmed on an ongoing basis since the required SSCs are performing their intended functions under design basis conditions during normal operation. Unlike the case for most safety-related equipment, the conditions under which these SSCs must perform their intended functions are the same conditions under which they operate during the course of normal plant operations. Performance of intended functions during normal plant operation demonstrates that the systems and components can perform those functions for one hour in the event of a fire in the auxiliary feedwater pump room.

The response to RAI 2.3A.4.5-2 describes the functions and flow paths of the systems credited for the AFW pump room fire event.

The following tables provide clarifying details regarding the passive, long-lived component types, materials, environments, aging effects and programs for SSCs that support the AFW pump room fire event that were not already included in scope and STAMR for 10CFR54.4(a)(1) or (a)(2).

Clarification Response for RAI 3.4.2-1

The Entergy response provided above in letter NL-09-018 dated January 27, 2009 is superseded by the following new commitment.

Commitment #39
Install a fixed automatic fire suppression system in the IP2 Auxiliary Feedwater Pump Room prior to entering the period of extended operation for IP2.

This commitment will delete the requirement for IP2 to place reliance on certain portions of the secondary plant systems for alternate secondary heat sink measures to cope with potential AFW Pump Room fire scenarios.

All of the tables that were provided in the January 27, 2009 letter are superseded by this commitment. The portions of the secondary systems that are in scope for 10 CFR 54.4(a)(1) and (a)(2) are not changed.

RAI-2.3A.4.5-2 (Unit 2)

In LRA Section 2.3.4.5 the applicant describes systems not described elsewhere in the application credited for mitigating the consequences of a Unit 2 fire event in the auxiliary feedwater (AFW) room. Each system listed has the following intended function: to support safe shutdown in the event of a fire in the auxiliary feed pump room (10 CFR 50.48) function in accordance 10 CFR 54.4(a)(3). The applicant states "no LRA drawings are provided based on the intended function of supporting safe shutdown in the event of a fire in the auxiliary feed pump room." However, the applicant states in LRA Section 2.2 that "[c]omponents subject to aging management review are highlighted on license renewal drawings, with the exception of components in scope for 10 CFR 54.4(a)(2)." Since the structures and components that support mitigating the consequences of a fire event are in scope in accordance with 10 CFR 54.4(a)(3) and subject to an AMR in accordance with 10 CFR 54.21(a)(1), then the components should have been highlighted on license renewal drawings. However, the applicant did not highlight the components or flowpaths needed to support this event. In addition, the applicant did not, in accordance with 10 CFR 54.21(a)(1), identify and list the structures and components that are subject to an AMR. Therefore, based upon the information provided in the LRA, the staff was not able to verify which components are included in scope to perform the stated function and are subject to an AMR.

For each system identified in LRA Section 2.3.4.5, the staff requests the applicant to a) identify the system support function for the AFW pump room fire event, b) clearly identify the portions of the systems' flow paths that support these functions that are subject to an AMR, and c) identify the portions of these flow paths that are not already in scope for 10 CFR 54.4(a)(1) or (a)(2).

Response for RAI-2.3A.4.5-2 (Unit 2)

Background
As discussed in section 2.3.4.5 of the LRA, a combination of secondary systems and components are credited for one hour for supplying make up water through the main feedwater isolation valves to the steam generators during the AFW (Auxiliary Feedwater) pump room fire event (Fire Zone 23/Fire Area C). This is necessary because under the current licensing basis, plant personnel are assumed unable to re-enter the AFW pump room for one hour following onset of the fire.

A conservative assessment of systems that support this event was performed for license renewal. For example, the wash water system was included in scope even though the travelling screens may not require cleaning during the one hour duration of the event, and several sources of instrument air were also included though only one would be needed.

Feedwater may be supplied by the main feedwater pumps in combination with the condensate pumps or by the condensate pumps alone after steam pressure is decreased. License renewal scoping conservatively identified systems that are required for main feedwater pump operation or condensate pump operation since this provides the maximum operator flexibility in response to the event. As a result, many auxiliary systems were included such as the main condenser to support the main feedwater pump turbine exhaust, circulating water to support condenser cooling, and main feedwater pump supporting sub-systems such as lube oil and cooling water.

The response to RAI-3.4.2-1 includes a specific listing of the component types that were not already in scope and STAMR for 10 CFR 54.4(a)(1) or (a)(2).

Clarification for RAI-2.3A.4.5-2 (Unit 2)

The Entergy response provided above in letter NL-09-018 dated January 27, 2009 is superseded by new commitment #39 as listed above.

The portions of the secondary systems that are in scope for 10 CFR 54.4(a)(1) and (a)(2) are not changed.

The portions of the secondary systems on IP2 that were credited for the AFW pump room fire event are deleted from scope in accordance with Commitment #39.

RAI 3.0.3.3.4-1

LRA Table B-2 identifies AMP B.1.18, Inservice Inspection Program, as a plant-specific condition monitoring program for the applications. The staff notes that Entergy has committed to enhance the "detection of aging effects" program element of the Inservice Inspection Program to revise the AMP to provide for periodic visual inspections of lubrite sliding supports used in the steam generator supports and reactor coolant pump (RCP) supports in order to confirm the absence of aging effects. Please specify (1) which aging effects and parameters will be monitored for by the visual examinations, (2) the types of visual examinations (e.g., VT-1, EVT-1, VT-2, or VT-3), (3) inspection frequency and sample size for the visual examination method that will be used to monitor for aging, (4) the acceptance criteria that will be used to evaluate the examination results, and (5) the corrective action or actions that will be implemented if the inspection results do not conform to the acceptance standard(s) for these components.

Response for RAI 3.0.3.3.4-1

The inservice inspection (ISI) program will employ visual inspections to confirm the absence of aging effects for steam generator (SG) and reactor coolant pump (RCP) lubrite sliding supports through the period of extended operation (PEO).

As described in LRA Section B.1.18, the ISI program is an existing program that encompasses requirements of ASME Code Section XI, Subsection IWF for ASME Class 1, 2, 3, and MC supports. The ISI program will be enhanced prior to the PEO to include explicit provisions for periodic inspections of the lubrite sliding supports. No aging effects requiring management have been identified for lubrite, but monitoring the surface condition of accessible surfaces will confirm the absence of age-related degradation. The inspections will be VT-3 visual examinations of SG and RCP lubrite sliding supports to determine their condition. The inspections will examine accessible surfaces of the lubrite and adjacent surfaces for wear or abnormal condition (surface roughness) that could potentially lead to lock-up or loss of function of the support. The lubrite will be examined in conjunction with Code required examinations of the support as a whole. The inspection frequency and sample size will be in accordance with the requirements of ASME Code Section XI, Subsection IWF. The supports must meet the acceptance standards described in IWF-3410(a), which includes no scoring or roughness on sliding surfaces. Any of the conditions described in IWF-3410(a) shall be corrected or evaluated for acceptance in accordance with IWF-3122.2 and IWF-3122.3, respectively. Corrective actions for this program will be administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B.

Clarification Response for RAI 3.0.3.3.4-1

The inservice inspection (ISI) program will employ visual inspections to confirm the absence of aging effects for steam generator (SG) and reactor coolant pump (RCP) lubrite sliding supports through the period of extended operation (PEO).

As described in LRA Section B.1.18, the ISI program is an existing program that encompasses requirements of ASME Code Section XI, Subsection IWF for ASME Class 1, 2, 3, and MC supports. No aging effects requiring management have been identified for lubrite, but monitoring the supports will confirm the absence of age-related degradation. The inspections will be VT-3 visual examinations of SG and RCP supports to determine their condition. The inspections will examine accessible surfaces of the supports for wear or abnormal condition (surface roughness) that could potentially lead to lock-up or loss of function of the support. The support structure attached to the lubrite will be examined in conjunction with Code required examinations of the support as a whole. The inspection frequency and sample size will be in accordance with the requirements of ASME Code Section XI, Subsection IWF. The supports must meet the acceptance standards described in IWF-3410(a), which includes no scoring or roughness on accessible sliding surfaces. Any of the conditions described in IWF-3410(a) shall be corrected or evaluated for acceptance in accordance with IWF-3122.2 and IWF-3122.3, respectively. Corrective actions for this program will be administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B.

Commitment

Enhance the ISI Program for IP2 and IP3 to provide periodic inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.

With respect to Commitment 11, the ISI Program already provides for periodic inspections of the supports used in the steam generator and reactor coolant pump support systems. The program includes the supports that utilize lubrite sliding surfaces. Visual inspection of those supports during the Spring 2009 refueling outage confirmed that the established inspections in accordance with ASME Code Section XI, Subsection IWF, already cover the accessible surfaces of the supports. Since the lubrite has no aging effects requiring management, the established ASME Section XI inspections provide reasonable assurance that the supports remain capable of performing their intended functions during the period of extended operation. Therefore, no commitment is necessary to enhance the ISI Program to address supports with lubrite sliding surfaces.

Commitment #11 will be deleted.

LRA Appendix A changes

(Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions)

A.2.1.17 Inservice Inspection – Inservice Inspection (ISI) Program

The ISI Program is an existing program based on ASME Section XI Inspection Program B (Section XI, IWA-2432), which has 10-year inspection intervals. Every 10 years the program is updated to the latest ASME Section XI code edition and addendum approved in 10 CFR 50.55a.

The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment of sign of degradation, flaw evaluation, and corrective actions.

On March 1, 2007, IP2 entered the fourth ISI interval. The ASME code edition and addenda used for the fourth interval is the 2001 Edition with 2003 addenda.

~~The ISI Program will be enhanced to include the following.~~

- ~~Revise appropriate procedures to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.~~

The current program ensures that the structural integrity of Class 1, 2, and 3 systems and associated supports is maintained at the level required by 10 CFR 50.55a.

A.3.1.17 Inservice Inspection – Inservice Inspection (ISI) Program

The ISI Program is an existing program based on ASME Section Xi Inspection Program B (Section XI, IWA-2432), which has ten-year inspection intervals. Every ten years the program is updated to the latest ASME Section XI code edition and addendum approved in 10 CFR 50.55a.

The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment of signs of degradation, flaw evaluation, and corrective actions.

On July 21, 2000, IP3 entered the third ISI interval. The ASME code edition and addenda used for the third interval is the 1989 Edition with no addenda.

~~The ISI Program will be enhanced to include the following.~~

- ~~Revise appropriate procedures to periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.~~

The current program ensures that the structural integrity of Class 1, 2, and 3 systems and associated supports is maintained at the level required by 10 CFR 50.55a.

LRA Appendix B changes

(Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions)

B.1.18 Inservice Inspection

Program Description

The Inservice Inspection (ISI) Program is an existing program that encompasses ASME Section XI, Subsections IWA, IWB, IWC, IWD and IWF requirements.

Regulation 10 CFR 50.55a, imposes inservice inspection (ISI) requirements of ASME Code, Section XI, for Class 1, 2, and 3 pressure-retaining components, their integral attachments, and supports in light-water cooled power plants. Inspection, repair, and replacement of these components are covered in Subsections IWA, IWB, IWC, IWD, and IWF, respectively. The program includes periodic visual, surface, and volumetric examination and leakage tests of Class 1, 2, and 3 pressure-retaining components, their integral attachments and supports.

Inservice inspection of supports for ASME piping and components is addressed in Section XI, Subsection IWF. ASME Code Section XI, Subsection IWF constitutes an existing mandated program applicable to managing aging of ASME Class 1, 2, 3, and MC supports for license renewal.

The program uses nondestructive examination (NDE) techniques to detect and characterize flaws. Three different types of examinations are volumetric, surface, and visual. Volumetric examinations using methods such as radiographic, ultrasonic or eddy current examinations are used to locate surface and subsurface flaws. Surface examinations, such as magnetic particle or dye penetrant testing, are used to locate surface flaws.

4. Detection of Aging Effects

The ISI Program manages cracking on subcomponents of the reactor vessel, as applicable, for carbon steel, nickel alloy, carbon steel with stainless steel cladding, and stainless steel components, including bolting, using NDE techniques specified in ASME Section XI, Subsection IWB examination category.

The ISI Program manages loss of material due to wear on reactor vessel internal subcomponents, as applicable, for nickel alloy and stainless steel clevis inserts, radial keys, core alignment pins, and head/vessel alignment pins using NDE techniques specified in ASME Section XI, Subsection IWB examination categories.

The ISI Program manages cracking on reactor coolant system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, stainless steel and cast austenitic stainless steel components, including bolting and support skirts, using NDE techniques specified in ASME Section XI, Subsection IWB examination categories. The Inservice Inspection Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel.

The ISI Program manages cracking on steam generator system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, and stainless steel components, using NDE techniques specified in ASME Section XI, Subsection IWB examination categories.

The ISI Program manages loss of material for ASME Class MC and Class 1, 2, and 3 piping and component supports and their anchorages and base plates by visual examination of components using NDE techniques specified in ASME Section XI, Subsection IWF examination categories.

No aging effects requiring management are identified for lubrite sliding supports. However, the Code required visual inspections of the supports under the ISI Program will confirm the absence of aging effects through the period of extended operation.

~~Enhancement: The ISI Program will be revised to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump supports. The ISI program will be enhanced prior to the PEO to include explicit provisions for periodic inspections of the lubrite sliding supports. No aging effects requiring management have been identified for lubrite, but monitoring the surface condition of accessible surfaces will confirm the absence of age-related degradation. The inspections will be VT-3 visual examinations of SG and RCP lubrite sliding supports to determine their condition. The inspections will examine accessible surfaces of the lubrite and adjacent surfaces for wear or abnormal condition (surface roughness) that could potentially lead to lock-up or loss of function of the support. The lubrite will be examined in conjunction with Code required examinations of the support as a whole. The inspection frequency and sample size will be in accordance with the requirements of ASME Code Section XI, Subsection IWF. The supports must meet the acceptance standards described in IWF-3410(a), which includes no scoring or roughness on sliding surfaces. Any of the conditions described in IWF-3410(a) shall be corrected or evaluated for acceptance in accordance with IWF-3122.2 and IWF-3122.3, respectively. Corrective actions for this program will be administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B.~~

~~Enhancements~~

~~The following enhancement will be implemented prior to the period of extended operation.~~ None

~~Attributes Affected~~	~~Enhancements~~
~~4. Detection of Aging Effects~~	~~Revise appropriate procedures to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.~~

ATTACHMENT 3 TO NL-09-056

IPEC Commitment List, Revision 8

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

List of Regulatory Commitments

Rev. 8

The following table identifies those actions committed to by Entergy in this document.

Changes are shown as strikethroughs for ~~deletions~~ and underlines for additions.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.1 A.3.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.10 A.3.1.10 B.1.11
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.12 A.3.1.12 B.1.13

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.15 A.3.1.15 B.1.16

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-09-018	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52
11	Delete commitment. ~~Enhance the ISI Program for IP2 and IP3 to provide periodic visual inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump support systems.~~	~~IP2: September 28, 2013~~ ~~IP3: December 12, 2015~~	~~NL-07-039~~ ~~NL-07-153~~ NL-09-056	~~A.2.1.17~~ ~~A.3.1.17~~ ~~B.1.18~~ ~~Audit item 59~~

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.18 A.3.1.18 B.1.19
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of bus inspected. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.21 A.3.1.21 B.1.22

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.22 A.3.1.22 B.1.23 Audit item 173
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.24 A.3.1.24 B.1.25 Audit item 173
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.25 A.3.1.25 B.1.26

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.28 A.3.1.28 B.1.29
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.32 A.3.1.32 B.1.33 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.1.34 A.3.1.34 B.1.35
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057	A.2.1.35 A.3.1.35 B.1.36 Audit items 86, 87, 88, 417

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material.			
	Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once		NL-08-127	Audit Item 360

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO.			Audit Item 358
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.36 A.3.1.36 B.1.37 Audit item 173
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: September 28, 2013	NL-07-039	A.2.1.40 B.1.41

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039	A.2.1.41 A.3.1.41
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	IP3: December 12, 2015	NL-07-039 NL-08-127	A.3.2.1.4 4.2.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039 NL-07-153 NL-08-021	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	April 30, 2008 Complete	NL-07-078 NL-08-074	2.1.1.3.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the extended period of operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127 NL-09-018	Audit Item 27
36	Perform a one-time Inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. <u>Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation.</u>	IP2: September 28, 2013	NL-08-127 <u>NL-09-056</u>	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127	Audit Item 361
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RTpts or C_VUSE, updated calculations will be provided to the NRC.	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-143	4.2.1
<u>39</u>	<u>Install a fixed automatic fire suppression system for IP2 in the Auxiliary Feedwater Pump Room.</u>	<u>IP2: September 28, 2013</u>	<u>NL-09-056</u>	<u>2.3.4.5 3.4.2</u>