Entergy

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March 13, 2002
Re: Indian Point Unit No. 2
Docket No. 50-247
NL 02-030

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

SUBJECT: Indian Point Nuclear Generating Unit No. 2 – Response to Request for Additional Information Regarding One-time Extension of Containment Integrated Leak Rate Test Frequency (TAC No. MB2414)

References:
1. Consolidated Edison letter (NL 01-093) to NRC, "Indian Point 2 License Amendment Request: Containment Integrated Leakage Rate Testing Frequency," dated July 13, 2001
2. NRC letter to Entergy Nuclear Operations, Inc., "Indian Point Nuclear Generating Unit No. 2 – Request for Additional Information Regarding One-Time Extension of Containment Integrated Leakage Rate Test Frequency (TAC No. MB2414)," dated October 4, 2001
3. Entergy Nuclear Operations, Inc. letter (NL 01-140) to the NRC, "Indian Point Nuclear Generating Unit No. 2 – Response to Request for Additional Information Regarding One-time Extension of Containment Integrated Leak Rate Test Frequency (TAC MB2414)" dated November 30, 2001
4. NRC letter to Entergy Nuclear Operations, Inc., "Request for Additional Information Regarding One-Time Extension of Containment Integrated Leak Rate Test Frequency, Indian Point Nuclear Generating Unit No. 2 (TAC No. MB2414)," dated February 5, 2002

By letter dated July 13, 2001 (Ref. 1), Consolidated Edison Company of New York, Inc., (the previous licensee) submitted an application for an amendment to the Technical Specifications (TS) for Indian Point Unit No. 2 (IP2). The proposed amendment would allow a one-time extension of the frequency for the containment integrated leakage rate test. The U.S. Nuclear Regulatory Commission (NRC) staff reviewed this submittal, determined that additional information was required to complete its review, and requested that additional information in its letter of October 4, 2001 (Ref. 2). Entergy Nuclear Operations, Inc. (ENO – the current licensee) submitted a response to the NRC's request for additional information in a letter (Ref. 3) dated November 30, 2001.

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After review of the ENO response, the NRC staff determined that further additional information was required to complete the review and requested that additional information in its letter of February 5, 2002 (Ref. 4). This letter submits the ENO response to the NRC's most recent request for additional information. Attachment 1 to this letter provides the requested additional information.

The assessment submitted in Ref. 1 that concluded that the proposed TS did not involve a significant hazards consideration is not affected by the additional information submitted herein in support of the application.

There are no commitments contained in this letter.

Should you or your staff have any questions regarding this submittal, please contact Mr. John F. McCann, Manager, Nuclear Safety and Licensing at (914) 734-5074.

Very truly yours,

Fred Dacimo
Vice President – Operations
Indian Point 2

cc: See Page 3

Attachments

cc:

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
ENTERGY NUCLEAR OPERATIONS, INC.	)	Docket No. 50-247
Indian Point Nuclear Generating Unit No. 2	)	

APPLICATION FOR AMENDMENT
TO OPERATING LICENSE

Pursuant to Section 50.90 of the Regulations of the U. S. Nuclear Regulatory Commission (NRC), Entergy Nuclear Operations, Inc., as holder of Facility Operating License No. DPR-26, hereby submits additional information to support the application for amendment of the Technical Specifications, contained in Appendix A of this license, submitted on July 13, 2001.

The specific additional information is set forth in Attachment 1. The assessment submitted on July 13, 2001 demonstrated that the proposed change does not involve a significant hazards consideration as defined in 10CFR50.92(c). That assessment is unchanged by the additional information.

As required by 10CFR50.91(b)(1), a copy of this submittal has been provided to the appropriate New York State official designated to receive such amendments.

BY: _____
Fred Dacimo
Vice President – Operations
Indian Point 2

Subscribed and sworn to
before me this 13 day
March, 2002.

_____
Notary Public

ERSILIA A. BOVIERO
Notary Public, State of New York
No. 01AM6038689
Qualified in Westchester County
Commission Expires March 20, 2004

ATTACHMENT 1

NL 02-030

Response to Request for Additional Information Regarding Proposed One-Time Extension of the Containment Integrated Leakage Rate Test Frequency

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

Request No. 1

On the basis of its review of the July 13 application and November 30 RAI response, the NRC staff noted that the IP2 containment has a number of areas of spalled and cracked concrete, corrosion of exposed reinforcing bars and cadweld splices, and liner corrosion. The licensee stated that corrective action for most of these degradations was not needed based on its engineering analysis.

The NRC staff notes that unobserved degradation can exist on the embedded (uninspectable) side of the steel liner of concrete containments. These degradations can only be found during visual examinations (VT-1 or VT-3) if the degradation is throughwall or by ultrasonic examination of the liner. With areas of degradation observed at IP2 and the possibility of degradation in uninspectable areas of the containment liner, provide the basis for not performing an ILRT before August 2002 to ensure the leak tightness of the "as is" containment.

Response to Request No. 1

The IP2 Vapor Containment is a steel-lined conventionally reinforced concrete structure. The concrete structure consists of a hemispherical dome on top of a cylindrical shell supported on a flat base mat. The inside surface of the concrete shell is covered by a welded steel liner which forms an envelope that functions to provide a leak tight barrier to control the release of radioactive material during postulated design accident conditions. The liner is not considered a strength element. With the exception of the dome, the design of the containment does not count on contribution from the liner in carrying structural loads.

The nominal thickness of the wall liner varies over the height of the containment. For the lower three rings (to approximately elevation 72'-9") the liner is ½" thick. The upper rings are 3/8" thick. Within these areas, panels of wall liner plate that contain penetrations are thickened to ¾". The liner in the dome is ½" thick. The wall liner is attached to the concrete by stud anchors.

The liner was fabricated from ASTM A442 Grade 60 plate. The plate is seam welded using full penetration welds and these seams are covered with weld channels. The weld channels are continuously pressurized to monitor the leak-tight integrity of the welded seams.

The floor of the containment building is a 3-foot thick concrete slab with the top surface at El. 46'-0". The slab is placed over the basemat liner and abuts the lower portion of the wall liner. A gap was maintained between the slab and the wall liner by a ½" thick premolded joint filler.

The caulk seal at the bottom of the insulation is considered under the Containment In-service Inspection (ISI) Program to be a moisture barrier. Moisture barriers are identified in the American Society of Mechanical Engineers (ASME) Boiler and Pressure

Vessel Code (B&PV Code) because they prevent intrusion of moisture into the slab-liner interface and thus protect the embedded portion of the liner, which is inaccessible for visual examination. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV Code), Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," Figure IWE-2500-2 depicts a typical moisture barrier and the surfaces requiring examination under IWE. While the configuration at IP2 differs somewhat from Figure IWE-2500-2, the caulking serves the purpose of preventing intrusion of moisture into the gap between the slab and the liner and thus it was included for examination.

I. IWE/IWL Inspection Results

10 CFR 50.55a(g)(6)(ii)(B), "*Expedited examination of containment*", required licensees of all operating power plants to implement the inservice inspections in the first period of the first inspection interval specified in Subsection IWE of the 1992 Edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV Code), Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components", with the 1992 Addenda in conjunction with the modifications specified in 10 CFR 50.55a(b)(2)(ix) by September 9, 2001.

Consolidated Edison contractor, Sargent & Lundy, conducted the required first period examinations of IP2 between March 10, 2000 and June 1, 2000 (Ref. 3) as follows:

- General Visual Examination of the containment liner,
- VT-3 Examination of 1/3 of the moisture barrier,
- VT-1 Examination of 1/3 of the bolted connections and
- VT-1C & VT-3C Examinations of the containment concrete surfaces.

The results of the examinations listed above are summarized below.

Liner General Visual Examination

The General Visual Examination of the containment liner was performed for all accessible areas of the containment liner, including penetrations and airlocks, in accordance with ASME BP&V Code, Subsection IWE, Table IWE-2500-1, Category E-A, Item E1.11 and revealed the following:

- Minor surface corrosion and/or coating deterioration was observed on 40 out of 116 electrical and mechanical penetrations. No significant loss of material was observed and the temperatures of the penetrations inhibit corrosion during normal operations.
- In all cases the primer coat was intact and only one isolated area of minor surface corrosion was observed in the liner at elevation 134'. This occurred in the center area of peeled topcoat.

- Portions of the moisture barrier (caulk between the concrete and insulation jacket at the liner/mat interface) were deteriorated. A closer inspection of these areas also showed evidence of liner corrosion. As a result, the moisture barrier and liner insulation were removed at several areas around the inner circumference of the liner to determine the extent of liner degradation. Removal of the insulation revealed liner corrosion had occurred primarily 2" above to 3" below the liner/mat intersection. The liner was observed to be dry with no moisture present. In accordance with the ASME BP&V Code requirements, volumetric examinations of the degraded areas were performed using ultrasonic testing (UT) methods.

Moisture Barrier

VT-3 examinations were performed on the moisture barrier in accordance with ASME B&PV Code, Subsection IWE, Table IWE-2500-1, Category E-D, Item E5.30. Although only 1/3 of the moisture barrier is required to be inspected during the first period, the entire moisture barrier was inspected and several areas were found to have the caulking degraded.

Bolting

VT-1 examinations were performed on the bolted connections in accordance with ASME B&PV Code, Section XI, Subsection IWE, Table IWE-2500-1, Category E-G, Item E8.10. No indications were identified.

Concrete Containment Inspections

VT-3C visual examinations were performed on all accessible surfaces of the containment exterior concrete for evidence of conditions indicative of damage or degradation in accordance with ASME B&PV Code, Section XI, Subsection IWL, Table IWL-2500-1, Category L-A, Item L1.11. Where suspect areas were identified, VT-1C visual examinations were performed in accordance with ASME B&PC Code, Section XI, Subsection IWL, Table IWL-2500-1, Category L-A, Item L1.12.

The results of the visual examinations revealed indications of 32 areas with spalling, leaching, exposed cadweld splices and reinforcing bars. The areas of exposed cadweld splices and reinforcing steel ranged from approximately 4 inches long by 3 inches tall to 9 inches long by 3 inches tall. All of the indications were isolated from each other and represent an area much less than 1% of the total surface area of the exterior concrete. Surface corrosion was identified on all of the exposed cadweld splices and reinforcing bars, however no flaking or aggressive corrosion process was observed on any of the exposed steel. There was no significant loss of cross section observed for any of the exposed cadweld splices and reinforcing steel.

II. Evaluation of IWE/IWL Findings

Liner

The required engineering evaluations of the identified surface corrosion and minor coating degradations of the containment liner indicated these degradations were acceptable, since they would have no effect on the structural integrity of the containment.

The required engineering evaluation of those areas where containment liner degradation had resulted in a loss of liner thickness included a review of past operating history to determine how the degradation could have occurred. The review indicated that a flooding event occurred in 1980 at the 46' elevation of containment when water leaked from the Service Water System. The water in this system comes from the Hudson River, which is known to be brackish. The chlorides found in the analysis of the corrosion by-products are consistent with brackish water. As a result, it was concluded that this flooding event is the most likely initiating event for the corrosion found on the containment liner and likely occurred over a relatively short period of time. This is consistent with the observation that the liner and joint filler were dry at the time of inspection, which is indicative of a past one-time event initiating the corrosion. No evidence of containment liner degradation was found at locations >3" above the 46' floor elevation. The corrosion observed was consistent throughout all areas inspected, with the minimum values occurring in areas below the slab. This was attributed to the pre-molded joint filler installed in the ½" gap between the floor slab and the liner acting as a wick during the flooding event.

The minimum general area liner thickness from the UT measurement readings of the 10 selected sample areas was determined to be 0.355" - 0.360". Three of the sample areas were found to contain this minimum value, however, the values measured were greater than the conservatively calculated design basis minimum required thickness of 0.34" determined in the visual inspection acceptance criteria for the inservice inspection (Ref. 1). The design basis minimum required thickness value of 0.34" was conservatively based on critical buckling stress. Since the portion of the liner with the identified degradation is insulated, no significant compression stress exists due to thermal loads and the minimum acceptable thickness due to pressure induced tensile stress is calculated to be approximately 0.18".

In one sample area where the minimum thickness reading of 0.355" occurred, a portion of the concrete in the containment mat had been previously chipped away from the liner. The concrete in this area was repaired and the liner coated with Carboline 890 to prevent future corrosion. In the other two areas, where the minimum thickness reading of 0.360" was measured, the moisture barrier was missing. The moisture barrier around the entire circumference of the containment at the 46' elevation was repaired as required to eliminate the

potential of any future water intrusion to the liner. Prior to closing containment during the 2000 RFO, the moisture barrier was inspected to verify the moisture barrier was functional.

Due to a lack of oxygen available to promote corrosion, and industry experience at other facilities, potential corrosion and corrosion rates on areas of the liner that are inaccessible (greater than 4" below the liner/mat intersection) will be much less than that observed as a result of these examinations. The areas of observed corrosion will be re-inspected during the next inspection period (2004 RFO) as required by the ASME BP&V Code, Section XI, Subsection IWE, Article IWE-2420.

The engineering evaluation of the liner corrosion (Ref. 2) conservatively calculated a potential future corrosion rate based on the laboratory analysis of the corrosion samples and assuming an environment of 70ºF and 43% relative humidity. The calculated potential future corrosion rate of less than 0.0011" per year will provide at least 18 years before the liner thickness in the most affected area would approach the most conservatively calculated design basis minimum required liner thickness of 0.34". With the potential for water intrusion eliminated and the very small corrosion rate, the IP2 Containment Liner should continue to meet the acceptance criteria of the ASME B&PV Code for inservice inspections. The acceptance criteria state that, if an engineering evaluation determines the reduced thickness continues to satisfy the requirements of the Design Specifications, the condition is acceptable by evaluation. The engineering evaluation of the liner corrosion (Ref. 2) demonstrates that a liner thickness as small as 0.0625" is acceptable to provide leak tightness based on scale model testing of a steel lined containment performed by Sandia National Labs (Ref. 4). Based on these results, the liner has significant margins even beyond the calculated design basis minimum required thickness value of 0.34" used as the inspection acceptance criteria for the inservice inspection of the IP2 Concrete Containment Structure.

Concrete

The limited indications of spalling and exposed cadweld splices and reinforcing bars are isolated instances and do not reduce the structural capacity or ability of the containment structure to perform its safety function based on the following:

- The observed corrosion for the cases of exposed reinforcing steel and/or cadwelds consisted of surface corrosion and was primarily the result of concrete spalling caused by insufficient cover. No flaking or aggressive corrosion processes were observed and the exposed reinforcing steel and/or cadwelds did not exhibit any discernable loss of cross-sectional area. The observed corrosion is primarily located in low stress regions and is well within the margins for the reinforcing steel. Based on the visual inspection acceptance criteria for the inservice inspection of the IP2 concrete

containment structure (Ref. 1), ongoing surface corrosion for 40 years would only result in a decrease of 10% in the reinforcing steel cross-section.

- Within inspection zone IWL-043-002, delaminations were found near the floor line and penetrations but no evidence of staining or exposure of reinforcing steel was observed. This portion of the concrete containment is not directly exposed to the environment. The visual inspection acceptance criteria for the inservice inspection of the IP2 concrete containment structure (Ref. 1), states that the reinforcing steel provides the structural strength to the concrete containment and is the primary concern. Staining of the concrete is the indication of possible corrosion of the reinforcing steel and is the first screening criteria for acceptance. Since no staining was observed, the reinforcing steel has not degraded in this area, and the structural capacity of the VC wall in this location is not degraded.

III. Conclusion

Based on the above, it is concluded that the liner is capable of satisfying the requirements of the Design Specifications. It is currently within the original design bases and will continue to be within the design bases for at least 18 years using the calculated maximum potential future corrosion rate and the most conservatively calculated design basis minimum required liner thickness of 0.34", which is based on buckling stress. Using the calculated minimum allowable thickness based on tensile stress of 0.18", the liner in the area of observed corrosion will continue to be within the design basis for as much as 164 years. The observed corrosion is attributed to a one-time past event and the repairs and preventive measures taken assure that future corrosion of the liner will be inhibited. There is no reduction in the structural capacity or ability of the containment structure to perform the intended safety function. The available margins, in both the reinforced concrete containment and inner steel liner, are well within the requirements of the design basis. Therefore, the structural integrity and leak tightness of the containment structure is assured and the surveillance interval for the ILRT may be extended for another 5 years without any significant additional risk.

IV. References

1. Visual Inspection Acceptance Criteria for In-Service Inspection of IP2 Concrete Containment Structure, by Raytheon Engineers, Revision 1, January 2000.
2. Evaluation of Containment Liner Corrosion at El. 46' Slab Interface, Report No. SL-5408, by Sargent & Lundy, Revision 0, June 28, 2001.
3. Containment Inservice Inspection First Period Examinations, March 2000 – June 2000, by Sargent & Lundy.
4. Horcschel, D. S., "Experimental Results from Pressure Testing a 1/6-scale Model Nuclear Power Plant Containment", NUREG/CR-5121, Prepared by USNRC by Sandia National Laboratories, Albuquerque, NM.

Request No. 2

The possibility of corrosion degradations in uninspectable areas of the liner or penetrations can potentially increase the area of liner leakage under a design basis accident pressure or under one of the severe accident scenarios. This could give rise to leak rates in excess of 35 L_a, (i.e., the threshold limit for Class 3b accident; see Attachment 3 to July 13 application). For a dry pressurized-water reactor containment such as the IP2 containment, NUREG-1493, "Performance-Based Containment Leak-Test Program," dated September 1995, estimates an approximate leak area of 6.5 square inches for a leak rate of 100% of containment air weight (1000L_a). Recognizing the potential for degradation in uninspectable areas at IP2, discuss how potential leakage is factored into the assumptions for the fragility curves that affect the Class 7 sequences related to risk assessments for the requested period of the CILRT extension.

Response to Request No. 2

I. Introduction

A sensitivity assessment has been performed to determine the impact of hypothetical corrosion in uninspectable areas of the IP2 containment liner on the previously submitted risk analysis (Ref. 1) associated with the requested one time extension of the IP2 Integrated Leak Rate Test (ILRT) surveillance interval from 10 to 15 years.

The sensitivity assessment includes the potential for a reduction in overall containment strength to resist overpressure as well as the potential for an increased leak rate during a severe accident. The previously submitted risk analysis was modified to account for the possibility of both of these effects. The general approach is similar to that in a recent submittal for the Susquehanna Steam Electric Station (Ref. 2) with the added feature that an increase in containment leakage was included for Classes 3b and 7 due to the effects of postulated undetected corrosion. The overall approach consists of developing a new set of accident class frequencies and person-rem/year impacts, which reflects the hypothetical case that the containment has a degraded liner due to undetected corrosion. These are then combined with the results for a non-degraded liner using an estimated liner failure rate that reflects the postulated degradation due to hypothetical undetected corrosion to obtain frequency and risk results.

II. Methodology

The specific steps of the analysis are as follows:

1. Estimate the reduction in containment failure pressure without taking credit for the strength of the containment liner. Assume the median failure

pressure is reduced by this amount and develop a new fragility curve using the above reduction in gauge pressure for each failure probability.

An evaluation of the capability of the Indian Point 2 containment to determine a confident lower bound of functional capability strength (Ref. 4) indicates that the ultimate capacity of the containment structure at the limiting zone is at least 126 psig. The containment liner contributes 14.8 psig and the remainder is due to the reinforcing steel in the concrete shell. If no credit were taken for the liner, the reduction in containment strength would be 14.8/126 = 0.12 or 12%.

2. Revise the frequency of late containment overpressure failures by changing the plant damage state (PDS) frequencies used in the Level 2 analysis (see Step 3 below) associated with late failures that are affected by containment failure probability. This is done by adjusting the split fraction representing the probability of power recovery before containment failure given that it has not been recovered by vessel failure for station blackout sequences to account for the reduced time to containment failure due to the lower assumed containment failure pressure (Ref. 3). This is based on the IPE analysis and containment pressure time history for no containment heat removal.

3. Revise the early containment failure probabilities in the IPE Level 2 analysis (Ref. 3) based on the new fragility curve above and determine the revised source term category (STC) frequencies for early and late containment failure (i.e. Class 7) by rerunning the analysis incorporating the revised PDS frequencies from Step 2.

4. Using the Class 7 frequency from Step 3, determine a revised Class 1 frequency so as to maintain the total core damage frequency (CDF) unchanged. The frequencies for all the other classes will not be affected by the containment liner condition.

5. Determine an effective Class 7 frequency, which accounts for the potential for liner failure based on an assumed constant liner corrosion failure rate and the assumption that the ILRT would detect this corrosion failure. Do this for 10 and 15-year ILRT intervals. The Class 7 frequency for the non-degraded liner is that in the previously submitted risk analysis. The other class frequencies would be determined as in the previously submitted risk analysis.

6. Determine the risk (person-rem/yr) for each class for the postulated degraded liner case using the frequencies for each class from Step 4 and the dose for each class from the previously submitted risk analysis except that the leakage rates and doses for Class 3b and Class 7 are increased by an assumed factor of 10 to 350La and 1000La, respectively. The risk,

a function of ILRT surveillance interval and accounting for the possibility of the postulated failure of the liner due to undetected corrosion, is then determined as in Step 5 using these degraded liner risks and the non-degraded liner risks from the previously submitted risk analysis.

7. Determine the change in risks in absolute and percentage terms due to changes in the ILRT surveillance interval.

8. Determine the change in LERF, due to extending the ILRT surveillance interval, as the sum of the increase in frequency of Class 3b (as determined for the previously submitted risk analysis) and the increase in frequency of that portion of Class 7 that could contribute to LERF. The frequency of these Class 7 contributors is determined as discussed in Step 5.

III. Results

The results of the above analysis are summarized in the following table.

	Prior Submittal (no liner degradation)	Sensitivity Study (12% reduction in strength)
Total Person-Rem/yr		
10 Year ILRT Interval	1.09E04	1.11E04
15 Year ILRT Interval	1.09E04	1.12E04
Increase in Total Person-Rem/yr when ILRT Interval increases from 10 to 15 years	6 0.055%	116 1.05%
Increase in LERF/yr when ILRT Interval increases from 10 to 15 years	3.6E-08	3.7E-08

Based on the sensitivity assessment performed in response to this request for additional information, the prior conclusion, that the risk impact of the requested extension is very small, remains valid even with the postulated liner corrosion.

Regulatory Guide 1.174 provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Very small changes in risk are defined in Regulatory Guide 1.174 as increases of CDF below 1.0E-06/yr or increases in LERF of less than 1E-07/yr. Since the ILRT does not impact CDF, the relevant criterion is LERF. The increase in LERF resulting from a change in the Type A ILRT test interval from once-per-10-years to once-per-15-years is 3.7E-08/yr even when considering the postulated potential for liner failure due to undetected corrosion. Since the guidance in Regulatory Guide 1.174 defines very small changes in LERF as less than 1.0E-7/yr and increasing the ILRT surveillance interval from 10 to 15 years would only result in a calculated

increase in LERF of 3.7E-08/yr, the prior conclusion that the increase in LERF due to the requested extension is considered non-risk significant remains valid even if the potential for liner corrosion is included.

IV. References

1. Consolidated Edison letter to the NRC (NL 01-093), "Indian Point 2 License Amendment Request: Containment integrated Leakage Rate Testing Frequency," dated July 13, 2001

2. PLA-5408, R. G. Byran (PPL), "Supplement No. 3 to Proposed Amendment No. 241 to License NPF-14 and Proposed Amendment No. 206 to License NPF-22: Request for a One Time Deferral of the Type A Containment Integrated Leak Rate Test (ILRT) and the Drywell-to-Suppression Chamber Bypass Leakage Test SR3.6.1.1.2," dated December 5, 2001

3. Consolidated Edison Company of New York, Inc., "Indian Point Unit Two Nuclear Generating Station Individual Plant Examination," August 1992

4. Power Authority of the State of New York & Consolidated Edison Company of New York, "Indian Point Probabilistic Safety Study", submitted to the NRC by letter dated March 5, 1982