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Vice President

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Letter No. 81-87

May 6, 1981

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

Director of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

ATTN: Mr. Steven A. Varga, Chief
Operating Reactors Branch No. 1
Division of Licensing

Dear Mr. Varga:

This letter is in response to your letter of February 3, 1981 regarding review of past Indian Point Unit No. 2 and Unit No. 3 LERs, specifically, LERs dealing with setpoint drifts, hydraulic snubber failures and electrical equipment malfunctions.

The Attachment to this letter assesses the above concerns and discusses corrective actions taken both from the standpoint of the individual events and possible generic causes. As was done for the original LER study provided to the Commission on August 11, 1980, the present additional LER review has been conducted jointly by Consolidated Edison and the Power Authority and covers the same reporting period of 1971-1979. For the reasons provided in our August 11, 1980 submittal, the LERs for both Unit 2 and Unit 3 were combined in order to provide a broader data base for examination and to better identify commonalities in the events reported for each unit.

Generally, assessments of this nature will be included in the operating experience feedback to the plant staff as required by Item I.C.5 of the TMI Action Plan. Specifically, this assessment will be forwarded to operating personnel.

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Con Edison considers it only natural that the Commission has found a large percentage of significant LERs occurring in safety systems. This is due to the nature of the LER reporting system as defined by the Commission in Regulatory Guide 1.16 and Technical Specification Limiting Conditions for Operation (LCOs). In addition, our review indicates that a relatively few reported malfunctions or failures occurred during the above mentioned period, compared to the total number of surveillance tests and routine checks performed by operating personnel.

Should you or your staff have any questions, please contact us.

Very truly yours,

John D. O'Toole

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Attach.

ATTACHMENT

I. Hydraulic Snubber Failures:

Eight (8) events for Unit 2 involving eleven (11) snubbers were reported between January 1974 and November 1979. These reports resulted from visual surveillance inspection of snubbers during this period. The majority of the reported items identified minor fluid leakage as resulting in snubber performance degradation, but no significant unit failures. The seismic support inspection and evaluation programs currently in effect at both units provide the capability for early detection of minor snubber degradation. A snubber exhibiting abnormal wear is modified with improved parts or is replaced with a new unit. Due to the low frequency of occurrence of these events and their negligible overall impact upon systems operation, due to their isolated nature, the current inspection and modification programs are adequate to preclude any significant safety impact arising due to the observed failure rates. Furthermore, technical specifications in effect since 1976 specify a variable snubber surveillance interval based on the number of failures identified during the previous inspection. Therefore, the frequency of surveillance inspections will increase with the number of snubber failures identified maintaining continued effectiveness of the established snubber surveillance program.

In addition, one (1) event at each Unit has been reported relative to snubber inoperability resulting from snubber functional (i.e., bench) testing. Snubber functional test requirements have only been incorporated into the technical specifications since 1978 and two such testing programs have been conducted at each unit during the subject report period. At each unit, one such testing program yielded no inoperable snubbers while the other testing program yielded a significant number of snubbers outside of the test acceptance criteria ranges. During early 1978, 35% of the Unit 2 snubbers were declared inoperable as a result of exceeding the snubber functional test criteria. During late 1979, 22.6% of the Unit 3 snubbers were likewise declared inoperable. In both cases, all hydraulic snubbers were functionally tested and those not meeting the test criteria were replaced. Insufficient data exists both on a plant-specific and generic basis to identify any predominating trends or generic root causes. More testing data from all nuclear plants must be gathered and disseminated before any conclusions can be drawn as to the appropriateness and effectiveness of this recently implemented generic test program.

II. Electrical Equipment Malfunctions:

A total of 48 events (29 for Unit 2, 19 for Unit 3) were included in this category. The majority of the items classified in this general category did not show any pattern of recurrence and therefore could not be readily attributed to any significant common root causes. The following cases are discussed as examples of events in this category and to clarify the types of causes for these specific events.

(1) Component Failures During Safeguards Actuation Testing:

Two instances of multiple component failures observed during safeguards actuation testing were reported in May 1977 and May 1978 at Unit 2. In the first case, one service water pump and one auxiliary component cooling pump failed to start, one motor operated valve failed to open, and two air operated valves failed to open. The causes for these failures, with the exception of that attributed to the air operated valves, were determined to be independent. The air operated valves experienced internal mechanical binding which, although not specifically identified in the event reports, could have resulted from common design, installation, application of maintenance, since the valves provide redundant functions. (A third valve in parallel with the two failed valves operated successfully). The internals of the two air operated valves were subsequently modified to effect a more reliable valve design. No significant systems degradation resulted from these failures. The second case resulted in failure of one auxiliary component cooling pump to start and one air operated valve to open, both of which were attributable to independent component failures.

(2) Heat Tracing Circuit Failures:

The three reported events of heat tracing circuit failures at Unit 2 occurred during a 4½ year period from August 1974 through March 1979. This low failure frequency and the isolated nature of the failures reported are not sufficient to indicate any significant commonalities in root causes.

(3) Diesel Generator 22 Voltage Control Failures:

During a 6 month period in 1974, three events were reported which identified a common failure cause in the voltage control circuitry for Diesel Generator 22. The defective components were replaced, and no recurrence of these or similar events has since been observed for any of the diesel generators at either unit.

(4) Instrumentation Power Supply Failures:

Although six (5 at Unit 2, 1 at Unit 3) reported events of instrumentation channel failures were identified as resulting from the general category of power supply failures, an analysis of the specific failure of these components indicates a relatively broad range of initiators (e.g., defective fuse clips, open capacitors, defective circuit boards, etc.). This range of failure causes, in conjunction with relatively low frequency of reported failures, provides insufficient evidence to cite a specific power supply design or operational deficiency as a common cause initiator.

No additional remedial action is planned at Unit No. 2 at the present time for the above malfunctions.

III. Setpoint Drifts:

(1) Instrumentation Setpoint Drift:

A total of 38 events (18 from Unit 2, 20 from Unit 3) were identified as attributable to root causes in this general category. Although the total number of events reported of this type is significant, the potential impact of these deviations from setpoint tolerances is uniformly minimal, resulting in, at worst, a slight delay in the initiation of a protection or safeguards system function and in no case preventing the associated function from occurring. The majority of these failures were discovered during periodic surveillance testing and/or performance of instrument channel calibration which accounts for the observed commonalities of reporting dates for many of the items. For both Unit 2 and 3, approximately two-thirds of these types of LER's occurred in the first two years of operation. The existing programs of functional systems testing and periodic calibration verification are adequate to detect major deviations in any subset of instruments and to identify any general trends in the failure data which would indicate any possible common failures.

(2) Mechanical Setpoint Drift:

Of the seven reported instances (4 at Unit 2, 3 at Unit 3) of mechanical component operating setpoint drift, four have been associated with deviations in the measured setpoints of the pressurizer safety valves detected during routine surveillance testing and recalibration.

It should be noted that of the seven valve setting deviations reported in these items, at least four resulted from setpoint drift in the conservative direction and, therefore, would not have prevented or delayed overpressure protection capability for the reactor coolant system. In the other cases, the reported deviations were less than 1% of the normal setpoint. These deviations, do not constitute a significant deficiency in system protection capability nor do they identify major component failures or trends, and the current testing program is considered adequate

No additional remedial action is planned at Unit No. 2 at the present time for the above identified setpoint drifts.