ATTACHMENT A

PROPOSED TECHNICAL SPECIFICATION CHANGES

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
MAY, 1993

P = Pressurizer pressure, psig

P' = 2235 psig

$K_1 \leq 1.22$

$K_2 = 0.022$

$K_3 = 0.00095$

and $f(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) For $q_t - q_b$ between -36% and +7%, $f(\Delta I) = 0$, where q_t and q_b are percent rated power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total power in percent of rated power;

(ii) For each percent that the magnitude of $q_t - q_b$ exceeds -36%, the ΔT trip setpoint shall be automatically reduced by 2.14% of its value at rated power; and

(iii) For each percent that the magnitude of $q_t - q_b$ exceeds +7%, the ΔT trip setpoint shall be automatically reduced by 2.15% of its value at rated power.

(5) Overpower ΔT:

$$\Delta T \leq \Delta T_o \left[K_4 - K_5 \frac{dT}{dt} - K_6 (T - T'')\right]$$

where:

ΔT = Measured ΔT by hot and cold leg RTDs, $^{\circ}F$

$\Delta T_o \leq$ Indicated ΔT at rated power, $^{\circ}F$

T = Average temperature, $^{\circ}F$

Table 3.5-1

Engineered Safety Features Initiation Instrument Setting Limits

No.	Functional Unit	Channel	Setting Limits
1.	High Containment Pressure (Hi Level)	Safety Injection	$\leq$ 2.0 psig
2.	High Containment Pressure (Hi-Hi Level)	a. Containment Spray b. Steam Line Isolation	$\leq$ 24 psig
3.	Pressurizer Low Pressure	Safety Injection	$\geq$ 1833 psig
4.	High Differential Pressure Between Steam Lines	Safety Injection	$\leq$ 155 psi
5.	High Steam Flow in 2/4 Steam Lines Coincident with Low T_{avg} or Low Steam Line Pressure	a. Safety Injection b. Steam Line Isolation	$\leq$ 40% of full steam flow at zero load $\leq$ 40% of full steam flow at 20% load $\leq$ 110% of full steam flow at full load $\geq$ 540°F T_{avg} $\geq$ 525 psig steam line pressure
6.	Steam Generator Water Level (Low-Low)	Auxiliary Feedwater	$\geq$ 7% of narrow range instrument span each steam generator
7.	Station Blackout (Undervoltage)	Auxiliary Feedwater	$\geq$ 40% nominal voltage
8a.	480V Emergency Bus Undervoltage (Loss of Voltage)	------	220V + 100V, -20V 3 sec ± 1 sec
8b.	480V Emergency Bus Undervoltage (Degraded Voltage)	------	403V ± 5V 180 sec ± 30 sec

Table 4.1-1

Minimum Frequencies for Checks, Calibrations and Tests of Instrument Channels

	Channel Description	Check	Calibrate	Test	Remarks
1.	Nuclear Power Range	S	D (1) M* (3)	Q (2)	1) Heat balance calibration 2) Signal to delta T; bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset.
2.	Nuclear Intermediate Range	S (1)	N.A.	S/U**(2)	1) Once/shift when in service Log level; bistable action (permissive, rod stop, trip)
3.	Nuclear Source Range	S (1)	N.A.	S/U**(2)	1) Once/shift when in service 2) Bistable action (alarm, trip)
4.	Reactor Coolant Temperature	S	R#	Q (1)	1) Overtemperature - delta T 2) Overpower - delta T
5.	Reactor Coolant Flow	S	R#	Q	
6.	Pressurizer Water Level	S	R#	Q	
7.	Pressurizer Pressure (High & Low)	S	R#	Q	
8.	6.9 kV Voltage & Frequency	N.A.	R	Q	Reactor Protection circuits only
9.	Analog Rod Position	S	R	M	

* By means of the movable incore detector system.

** Prior to each reactor startup if not done previous week.

Table 4.1-1

Minimum Frequencies for Checks, Calibrations and Tests of Instrument Channels

	Channel Description	Check	Calibrate	Test	Remarks
10.	Rod Position Bank Counters	S	N.A.	N.A.	With analog rod position
11.	Steam Generator Level	S	R#	Q	
12.	Charging Flow	N.A.	R#	N.A.	
13.	Residual Heat Removal Pump Flow	N.A.	R#	N.A.	
14.	Boric Acid Tank Level	W	R	N.A.	Bubbler tube rodded during calibration
15.	Refueling Water Storage Tank Level	W	R	N.A.	
16.	DELETED				
17.	Volume Control Tank Level	N.A.	R	N.A.	
18a.	Containment Pressure	D	R#	Q	Wide Range
18b.	Containment Pressure	S	R#	Q	Narrow Range
18c.	Containment Pressure (PT-3300,PT-3301)	M	R#	N.A.	High Range
19.	Process Radiation Monitoring System	D	R	M	
19a.	Area Radiation Monitoring System	D	R	M	
19b.	Area Radiation Monitoring System (VC)	D	R#	M	

Table 4.1-1

Minimum Frequencies for Checks, Calibrations and Tests of Instrument Channels

	Channel Description	Check	Calibrate	Test	Remarks
20.	Boric Acid Make-up Flow Channel	N.A.	R	N.A.	
21a.	Containment Sump and Recirculation Sump Level (Discrete)	S	R#	R#	Discrete Level Indication Systems.
21b.	Containment Sump, Recirculation Sump and Reactor Cavity Level (Continuous)	S	R#	R#	Continuous Level Indication Systems.
21c.	Reactor Cavity Level Alarm	N.A.	R#	R#	Level Alarm System
21d.	Containment Sump Discharge Flow	S	R	M	Flow Monitor
21e.	Containment Fan Cooler Condensate Flow	S	R#	M*	
22a.	Accumulator Level	S	R#	N.A.	
22b.	Accumulator Pressure	S	R#	N.A.	
23.	Steam Line Pressure	S	R#	Q	
24.	Turbine First Stage Pressure	S	R#	Q	
25.	Reactor Trip Logic Channel Testing	N.A.	N.A.	M[1]	
26.	Turbine Overspeed Protection Trip Channel (Electrical)	N.A.	R#	M	

* Monthly visual inspection of condensate weirs only.

ATTACHMENT B

SAFETY ASSESSMENTS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247
MAY, 1993

SAFETY ASSESSMENT

CONTAINMENT PRESSURE CHANNELS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247

DESCRIPTION OF CHANGE

The current Indian Point Unit 2 Technical Specifications require that the Containment Pressure channels be capable of providing a High Safety Injection signal with a Nominal Trip Setpoint of $\leq$2.0 psig (Table 3.5-1 item #1); containment spray and steam line isolation with a Nominal Trip Setpoint of $\leq$30.0 psig (per Table 3.5-1 item #2); and, that a channel calibration be performed at every refueling outage (Table 4.1-1, items #18a, 18b, and 18c). Currently this calibration is performed every 18 months (+25%). It is proposed that this calibration frequency be revised to every 24 months (+25%). This change is being made in accordance with the guidance contained in Generic Letter 91-04.

All completed test procedures from the February 1986 outage to the present were reviewed. This review included any midcycle outage calibrations that may have resulted due to channel failures or modifications, and the impact of Measurement and Test Equipment (M&TE) used to record the data. The "As Left/As Found" data from the completed test procedures was statistically evaluated to determine a projected 30 month drift value with a 95% probability at a 95% confidence level for the Technical Specification parameters.

The results of the channel statistical calculations show that the channel uncertainties exceed those which can be supported by the current Technical Specification and the current safety analysis limits. For the containment high pressure setpoint, revision of the safety analysis limit (SAL) from 2 psig to 7.3 psig was found necessary to maintain the current technical specification limit of 2 psig. Revising this value lower is impractical from the viewpoint of plant operation. For the containment high high pressure limit, the safety analyses limit is being maintained at 30 psig and the Technical Specification value is being revised to 24 psig.

Since the proposed increase in the containment pressure setpoint to 7.3 psig is not considered in the current licensing basis LOCA accident analyses, an evaluation of the effects of the increase on the analysis assumptions and results for LOCA related accident analyses has been performed.

The potential impacts on the other safety-related components and licensing basis analyses have been reviewed and found not to be affected by the containment pressure SAL relaxation. These areas include:

- Primary Component and Systems Licensing Considerations
- Instrumentation and Controls/Equipment Qualification Considerations
- Radiological Consequences
- Non-LOCA Analyses
- Steam Generator Tube Rupture
- Probabilistic Risk Assessment
- Emergency Operating Procedures

The evaluation demonstrated that the peak calculated containment pressure will be less than the containment design and Integrated Leak Test (ILRT) value of 47 psig as identified in WCAP-12237, entitled, "Containment Integrity Analysis for Indian Point Unit 2 - December, 1989", and as specified in the Indian Point Unit 2 Technical Specifications (Section 4.4 A.1.a). This evaluation also accounted for other effects. These include effects stemming from the Ultimate Heat Sink (UHS) program, the Containment Integrity Analysis to support the Stretch Program, degraded RHR pump flows, and effect of degraded ECCS flows due to a change in the flow balance criteria.

CONTAINMENT INTEGRITY ANALYSIS

The containment integrity analyses are described in Chapter 14 of the Indian Point Unit 2 FSAR. This chapter considers: Short Term and Long Term Mass and Energy Release Analyses for Postulated Loss of Coolant Accidents (LOCA's); Containment Response Analyses following a LOCA or Steamline Break Inside Containment; and Subcompartment Pressure Transient Analyses.

Short Term Mass and Energy Releases/Subcompartment Pressure Analyses

For the short term mass and energy release and subcompartment pressure analyses, relaxation in the containment pressure SAL would have no effect on the calculated results, since the SAL change would not factor into the analysis because of the short duration of the transient ($\leq$ 3 seconds). Thus, the current analysis remains valid.

LOCA Mass and Energy Release

The long term mass and energy release and containment pressure response calculations following a LOCA consider the effects of long term depressurization and secondary side heat transfer. The analyses considered the total energy available to the containment from both the primary and secondary side sources at all particular time segments of the transient.

Similar to the short term analysis evaluation basis, mass and energy release analyses were performed to conservatively maximize the mass and energy release available to the containment.

In addition to the effect of the containment pressure SAL relaxation change, this evaluation accounted for the effects of other plant changes as identified earlier. Based upon the results of the evaluation there is a reduction of 0.6 psi on the peak pressure at the stretch power level of 3083.4 MWt, when the cumulative effect of the containment pressure SAL relaxation and the issues identified earlier are included. At the increased power level of 3216 MWt, a reduction of 0.8 psi was calculated. The resulting peak pressure at the stretch power level of 3083.4 MWt becomes 40.89 psig (at the increased power of 3216 MWt, the peak pressure becomes 41.49 psig), both less than the containment design and integrated Leak Rate Test (ILRT) Technical Specification value of 47 psig. Therefore, the Indian Point Unit 2 design basis analysis of record and its conclusions remain valid, and margin is maintained between the peak calculated containment pressure and the design pressure.

MSLB Inside Containment

Containment response calculations for postulated steam line break mass and energy releases inside containment demonstrate that the containment pressure would not exceed acceptable levels. The Hot Full Power, Feedwater Control Valve Failure case is the current limiting case for containment response following a MSLB. The existing MSLB mass and energy releases inside containment for Indian Point Unit 2 are not affected by changing the high pressure setpoint. Specifically, no credit for these signals have been taken in the steamline break analyses used to generate the existing licensing basis mass and energy release for Indian Point Unit 2. For the containment response calculation credit for the containment pressure signal is assumed. The limiting case was reanalyzed assuming a relaxed SAL Limit of 7.3 psig. The peak containment pressure for the limiting MSLB event was calculated to be 40.03 psig, or a increase of 0.04 psi resulting from the relaxation of the SAL containment pressure limit assumed in the previous containment analysis. This pressure is less than the containment design and ILRT pressure of 47 psig. Thus, margin is maintained between the peak calculated containment pressure and the design pressure.

Peak Sump Temperature

The peak sump temperature calculation is not an explicit FSAR Chapter 14 safety analysis. However, the results are input for the Ultimate Heat Sink Analysis. There is an insignificant impact with respect to the containment pressure SAL relaxation considered herein on the current peak sump temperature. The value remains at 250°F.

LOCA RELATED ANALYSES

LOCA related accident analyses are described in Chapter 14 of the Indian Point Unit 2 FSAR. An assessment of the LOCA related analyses was included within the scope of this evaluation addressing the proposed increase to the containment high pressure setpoint. The following LOCA related analyses were evaluated:

- Large Break LOCA
- Small Break LOCA
- Post-LOCA Long-Term Core Cooling
- Hot Leg Switchover
- LOCA Hydraulic Forces

Large Break LOCA

The large break LOCA (LBLOCA) analysis is impacted because the containment pressure high ESF trip setpoint is modeled in a portion of the 1981 Evaluation Model with BASH. The current safety analysis limit is 2 psig. This is also the current value given in the Technical Specifications. It was determined that the increase in the containment high pressure setpoint would cause an approximate delay of 3 seconds in delivering the pumped ECCS injection. The delay time for the safety injection assumed in the analysis is 25 seconds. Thus, the time at which safety injection would be delivered is increased from the previous time of 25.5 seconds to the revised time of 28.5 seconds. However, from the analysis of record, the end of bypass time (EOB) is 37.2 seconds. This is the time at which the water in the vessel has exited through the break. At this time, the refill period begins, whereby the vessel begins to refill by pumped safety injection. Since the increase in the safety injection time does not increase the delivery time of the pumped safety injection past the EOB time, the LBLOCA analysis will be unaffected, since all safety injection flow before that time exits out the break. Consequently, the LBLOCA analysis is unaffected by the proposed increase in the containment high pressure setpoint.

Originally the high containment pressure set point was limited to provide a diverse backup to low pressurizer pressure reactor trip. The value was limited to 2 psig in order that a diverse signal would occur prior to emptying of the pressurizer. Raising the containment pressure actuation point to 7.3 psig will not provide the same timely reactor trip from containment pressure although it will continue to provide a diverse signal. Rather diversity of signal is now provided by the low pressurizer ESF trip signal which is derived from a separate and diverse logic train. In addition, the over temperature delta-temperature (OTDT) reactor trip is available for a diverse reactor trip in the event of a depressuration of the primary system. The change in the containment pressure actuation limit does not significantly affect the protection system diversity for small breaks in the primary system.

Small Break LOCA

Small Break LOCA (SBLOCA) does not model the effects of containment pressure or temperature due to the prolonged duration of the transient. Further, the containment pressure does not reach the containment high set point before the pressurizer pressure low setpoint is reached. Thus, during a SBLOCA, the reactor would not trip on the containment high pressure setpoint, and the SBLOCA analysis is not impacted by an increase in the containment high pressure setpoint.

LOCA Hydraulic Forcing Functions

The blowdown hydraulic forcing functions resulting from a LOCA are also considered in the FSAR. The LOCA hydraulic forcing functions are primarily affected by temperature, pressure, density, enthalpy and losses in the reactor vessel, reactor coolant loop and steam generators. The LOCA hydraulic forcing functions (LHFF) analysis methodology does not model setpoints. As such, the proposed increase in the containment high pressure setpoint does not affect the LHFFs.

Post LOCA Long Term Core Cooling

Following a postulated Large Break LOCA, the reactor would become subcritical initially due to massive voiding in the core region. Since credit for control rod insertion is not taken for Large Break LOCA, the boron concentration of injected water must be sufficiently high as to maintain the core in a shutdown condition. This calculation is based on the primary system water volumes and boron concentrations. The Long Term Core Cooling (LTCC) sump criticality evaluation is affected by changes in volumes and boron concentrations of the Emergency Core Cooling System components. Since setpoints are not modeled in this evaluation methodology, the LTCC evaluation methodology is not impacted by the proposed increase in the containment high pressure setpoint.

Hot Leg Switchover to Prevent Potential Boron Precipitation

Post LOCA hot leg switchover time is determined for inclusion in emergency operating procedures to ensure no boron precipitation in the reactor vessel following boiling in the core. This time is strongly dependent on initial core power and the boron concentration of the fluid residing in the sump/RCS post LOCA. The proposed increase to the containment high pressure setpoint will increase the calculated time at which safety injection is initiated. The hot leg switchover analysis is not affected by the increase in the containment pressure high setpoint because the net change to the integrated safety injection is negligible compared to the total integrated safety injection over 24 hours.

DIESEL GENERATOR LOADING STUDY

Indirect Impacts Due to Containment Pressure Increases

As noted in the containment integrity evaluations, the pressure following a LOCA event decreases approximately 0.6 psi for stretch power level of 3083.4 MWt due to the combined effects plant specific reanalysis. As a result of decreased peak containment pressure, the loads on the diesel generator will decrease because the fan cooler units will require less power to operate at the lower containment pressure. The current diesel generator loading analysis is based upon the higher design basis analysis; therefore, these calculations remain bounding.

With respect to the changes in the Technical Specification limit for the high high containment pressure signal, the change is in the conservative direction initiating ESF actuation at a lower containment pressure.

BASIS FOR NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The proposed change does not involve a significant hazards consideration since:

1. There is no significant increase in the probability or consequences of an accident.

No revision of the Technical Specification setpoint for containment high pressure actuation is required to accommodate a 30 month operating cycle. A safety evaluation has been performed which demonstrates that changing the safety analysis limit to 7.3 psig does not increase the probability or consequences of an accident previously analyzed in the FSAR. The margin that exists between the technical specification limit of 2 psig and the safety analyses limit of 7.3 psig is sufficient to assure with 95% reliability and 95% confidence that the channel uncertainty within the 30 month operating period will not result in exceedance of the Safety Analysis limit.

For containment high high pressure actuation, the technical specification limit (and therefore the plant setpoint) has been adjusted in the conservative direction, providing for ESF actuation in a shorter period of time. The safety analysis limit has not been changed. The margin between the technical specification limit and the safety analysis limit is sufficient to provide with a 95% reliability and 95% confidence level that the channel uncertainty over a 30 month period will not result in exceedance of the Safety Analysis limit. Therefore, adequate assurance exists that there has been no significant increase in the probability or consequences of an accident previously analyzed in the FSAR.

2. The possibility of a new or different kind of accident from any previously analyzed has not been created.

   Since adequate margin exists beyond the technical specification limits for containment high pressure and containment high high ESF actuation to assure that Safety Analyses limits will not be exceeded for a 30 month operating cycle, the possibility of a new or different kind of accident from any previously analyzed has not been created.

3. There has been no reduction in the margin of safety.

   The changes recommended herein increase the margin between the technical specification limits and the safety analysis limits in comparison to the previous values. Therefore, there has not been a reduction in the margin of safety.

SAFETY ASSESSMENT

STEAM PRESSURE CHANNELS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247

DESCRIPTION OF CHANGE

Technical Specification Table 3.5-1, items 4 and 5, require that the steam pressure channels be capable of providing a safety injection signal on high differential pressure between steam lines, and low steam pressure coincident with high steam flow in two out of four steam lines. Furthermore, Table 4.1-1, item 23 requires a quarterly test and a calibration at refueling intervals. Currently the channels are calibrated at 18 month (+25%) intervals. It is proposed that the calibration interval be changed to 24 months (+25%). This change is being made in accordance with Generic Letter 91-04.

Completed test procedures from the February 1985 outage to the present were reviewed, including any midcycle calibrations resulting from channel failures or modifications, and the impact of Measurement and Test equipment (M&TE) used to record the data. The "As Left/As Found" data from the completed test procedures was statistically evaluated to determine a projected 30 month drift value with a 95% probability at a 95% confidence level. This drift value was used as an input to determine the Channel Statistical Allowance (CSA) using the Westinghouse setpoint methodology. Included in the evaluation along with instrument drift is the determination of all other channel uncertainties, including Sensor, Rack, M&TE, and Process Effects for normal environmental conditions.

The results of the channel statistical calculations show that the channel uncertainties do not exceed those which can be supported by the current Technical Specification setpoint. However, to accommodate the increased channel uncertainty due to a possible 30 months operating cycle, the high differential steam pressure setpoint reflected in the safety analysis was found to require revision. The current safety analysis limit for this trip is 215 psi. The required safety analysis limit is 270 psi, which also permits a slight change in the Technical Specification limit, currently 150 psi, to 155 psi to provide operating flexibility.

For the high steam flow coincident with low steam pressure ESF trip, additional plant operating flexibility is desired although not necessitated by channel uncertainty. A change in the safety analysis limit from 445 psig to 400 psig will permit revision of the Technical Specification limit from 600 psig to 525 psig.

A safety analysis has been performed which addresses the effect on safety related components and the licensing basis. It has been determined that the effect of the proposed changes are limited to non-LOCA safety analyses and safety systems setpoints. The other areas reviewed and determined not to be affected by the aforementioned changes include:

- Primary Components and System Licensing Considerations
- Instrumentation and Controls/Equipment Qualification Considerations
- Radiological Consequences
- Containment Design
- Non-LOCA Analyses

- Steam Generator Tube Rupture
- LOCA Related Analyses
- Probabilistic Risk Assessment
- Emergency Operating Procedures
- Technical Specifications

For the non-LOCA safety analyses, only the Steam Pipe Rupture event is affected.

For the Indian Point Unit 2 FSAR licensing basis non-LOCA transients, only SI actuation and steamline isolation is credited in the analysis of the Steam Pipe Rupture event as described in section 14.2.5 of the Indian Point Unit 2 FSAR. Therefore, an evaluation of the Main Steam Line Break (MSLB) cases for this event which specifically models these setpoints was performed. The results show that the revisions to these safety injection setpoints will have no adverse effect on MSLB core response or resulting mass and energy releases inside containment.

Specifically, for the limiting core response MSLB (postulated to occur upstream of the flow restrictor with offsite power), the increase in the High Steamline Differential Pressure setpoint to 270 psi results in the setpoint being reached in 2 loops (2 out of 4 logic) 0.6 seconds later. This delays feedwater isolation and safety injection actuation by 0.6 seconds. However, this has no adverse effect on the resulting MSLB core response transient conditions for this limiting case. Steamline isolation is still actuated on a high steam flow (HSF) coincident with Lo-Lo Tavg (536°F) at 12.3 seconds with isolation occurring at 21.3 seconds (i.e., no credit for the Low Steamline Pressure setpoint portion of the HSF coincidence logic is taken).

For the limiting hot full power (HFP) MSLB mass and energy release case (again, upstream of the flow restrictor with offsite power), the increase in the High Steamline Differential Pressure Setpoint to 270 psi results in the setpoint being reached in 2 loops (2 out of 4 logic) 0.4 seconds later. This delays Feedwater isolation and Safety Injection actuation by 0.4 seconds. However, this delay has no adverse effect on the resulting MSLB mass and energy release rates for this limiting case. Steamline isolation of the intact loops is assumed to occur via closure of the fast-closing reverse steam flow check valve in the faulted loop. Hence, no steamline isolation signal is required (i.e., no credit for the Low Steamline Pressure setpoint portion of the HSF coincidence logic is taken).

Therefore, it is concluded that an increase in the High Steamline Differential Pressure SI actuation setpoint from 215 psi to 270 psi and a decrease in the Low Steam line Pressure (on the High Steam Flow coincidence SIS Logic) SIS actuation setpoint from the 445 psig to 400 psig would be acceptable.

BASIS FOR NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The proposed change does not involve a significant hazards consideration since:

1. The probability of an accident previously evaluated in the FSAR will not be increased.

   The subject change to the ESF setpoints is not associated with events involved in the initiation of any accident previously evaluated in the FSAR. In any case, it has been demonstrated that all pertinent licensing-basis acceptance criteria have been met. Therefore, the subject change in the ESF setpoints does not increase the probability of an accident previously evaluated in the FSAR. Furthermore, it has been demonstrated that all pertinent licensing-basis acceptance criteria have been met for the subject change in the ESF setpoints. Therefore, the subject change does not increase the consequences of an accident previously evaluated in the FSAR.

2. The possibility of an accident which is different than any already evaluated in the FSAR has not been created.

   The subject change in the ESF setpoints neither results in the initiation of any accident, nor do they create any new credible limiting single failure. Furthermore, they do not result in any previously incredible event becoming credible. The plant design basis considered in the FSAR is unaffected and remains bounding. Therefore, the possibility of an accident which is different than any already evaluated in the FSAR is not created.

3. The margin of safety as defined in the bases to any technical specifications has not been reduced.

   It has been demonstrated that all pertinent licensing basis acceptance criteria have been met. Compliance with the safety acceptance criteria provides assurance that there will be no degradation in the margin to safety to pertinent design failure limits. Therefore, the margin to safety as defined in the bases to any technical specification will not be reduced.

SAFETY ASSESSMENT

REACTOR COOLANT TEMPERATURE CHANNELS

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
INDIAN POINT UNIT NO. 2
DOCKET NO. 50-247

DESCRIPTION OF CHANGE

Technical Specification Table 4.1-1, Item #4, requires that the Reactor Coolant Temperature Channels be calibrated at refueling intervals. Currently, this surveillance is performed every 18 months (+25%). It is proposed that the surveillance frequency be changed to every 24 months (+25%). This change is being proposed in accordance with the guidance contained in Generic Letter 91-04.

The current Indian Point Unit 2 Technical Specifications require that the RCS narrow range temperature channels (Tavg and Delta T) be capable of providing a reactor trip on Overtemperature ΔT with nominal trip setpoints of K1 $\leq$ 1.25; Overpower ΔT with nominal trip setpoint of K4 $\leq$ 1.074 (Section 2.3.B); and, providing Safety Injection initiation and Steam Line Isolation on Low Tavg coincident with High Steam Flow with a nominal trip setpoint of $\geq$ 540 Deg F (Table 3.5-1). In addition to the reactor trip and SI functions, Tavg Indication is used by the operators as the method of determining acceptable operating Tavg (Rod Control).

Completed test procedures from the February 1986 outage to the present were reviewed, included midcycle outage calibrations that may have resulted due to channel failures or modifications, and the impact of Measurement and Test Equipment (M&TE) used to record the data. The "As Left/As Found" data from the completed test procedures was statistically evaluated to determine a projected 30 month Allowance (CSA) using the Westinghouse setpoint methodology. Included in the evaluation along with instrument drift was the determination of all other channel uncertainties including Sensor, Rack, M&TE, and Process Effects for normal environmental conditions.

The RCS Temperature channels were reviewed using the Westinghouse methodology for evaluating channel uncertainties. Each uncertainty term was determined according to the instrument characteristics/specifications and with specific calculations for process effects. Particular effort was made to predict a drift for the instrumentation over a 30 month period based on a statistical evaluation of plant recorded "As Left/As Found" data taken at the site since 1986. Past cycle calibration data was evaluated to determine how well the instruments had performed from one cycle to the next. This evaluation included a review of any work order data that may have been taken during a midcycle outage, or any modifications to the channels. Also, past M&TE accuracies were reviewed to insure that the M&TE used was of an equivalent accuracy such that it would not have biased the data in a non-conserative direction.

Evaluation of Tavg Control (Rod Control) was based on operator use of the control board indicators and not on the accuracy of the Auto Rod Control system. The operators will use the mathematical average of the Tavg indicators to determine actual plant Tavg and move rods accordingly to achieve the correct Tavg.

The results of the channel statistical calculations showed that the channel uncertainties would exceed those which can be supported by the current Technical Specification setpoint and the current Safety Analysis Limits for the K1 overtemperature ΔT setpoint. The K4 Overpower ΔT, and the Tavg Low setpoints are acceptable as is. Therefore, setpoint changes or changes to the safety analysis will have to be implemented in order to support an extended surveillance interval of up to 30 months. Based on the use of plant indications for Tavg (rod control), Consolidated Edison will put into place administrative procedures which provide that the operators will control the plant to within the temperature uncertainty currently assumed in the safety analysis. The temperature uncertainty currently assumed in the analysis is 7.5 deg F. The following uncertainties are calculated for these channels:

Function	CSA
Single Indicator	6.2% or 4.65 deg F
Rod Control	
(3 indicators)	4.4% or 3.3 deg F
(4 indicators)	4.1% or 3.1 deg F

Based on the above uncertainties, a change in K_1, Over temperature ΔT setpoint from 1.25 to 1.22 is required to support operation over a 30 month cycle.

BASIS FOR NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

The proposed change does not involve a significant hazards consideration since:

1. There is no significant increase in the probability or consequences of an accident.

   Regulatory Guide 1.105 Rev. 2 sets forth a method and basis acceptable to the NRC for compliance with NRC's regulations for ensuring that instrument setpoints are initially within and remain within Technical Specification limits. The evaluation of historical data for the RCS temperature instrument channels was accomplished in a manner more conservative than that required by the Regulatory Guide. The conclusion of this evaluation was that automatic protective actions over an extended operating cycle (30 months) will take place for the RCS temperature channels so that FSAR safety analysis limits will not be exceeded.

2. The possibility of a new or different kind of accident from any previously analyzed has not been created.

   As historical data provides an acceptable statistical data base to conclude that protective actions will occur without exceeding safety analysis limits, the possibility of a new or different kind of accident from any previously analyzed has not been created.

3. There has been no reduction in the margin of safety.

   Since historical data, together with a method for combining instrument channel error, indicates that safety analysis limits will not be exceeded during a thirty month operating cycle, there is no impact upon the margin of safety.