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December 26, 2007

DOCKETED
USNRC

December 28, 2007 (4:37pm)

OFFICE OF SECRETARY
RULEMAKINGS AND
ADJUDICATIONS STAFF

Mr. Emile Julian
Office of the Secretary
16th Floor
11555 Rockville Pike
Rockville, MD 20852

RE: Fire Protection Petition filed on 12/3/07 and Petition for Leave to Intervene with Contentions and Request for Hearing: RE: Indian Point Docket Nos 50-247-LR and 50-286-LR ASLB No. 07-858-03-LR-DB01, DPR 26 and DPR 64 filed on 12/10//07 of WestCAN, RCCA, PHASE, SIERRA CLUB and Richard Brodsky

Dear Mr. Julian:

Please find enclosed 3 copies of clarifications of indexes and exhibits to the above Petitions which Martin O'Neill of Morgan Lewis & Bockius, LLP and Sherwin Turk of the NRC requested.

Exhibits J, K.V, EE, HH, WW, XX, JJJ and all the Fire Protection exhibits have been reprinted in their entirety, for the sake of clarity.

The enclosed exhibits and indexes supercede the exhibits previously submitted.

Happy Holidays.

Sincerely yours,

Susan Shapiro & Richard Brodsky

SECY-02

TEMPLATE = SECY-037

WestCAN, RCCA, PHASE, SIERRA CLUB and
ASSEMBLYMAN RICHARD BRODKSY

PETITION TO INTERVENE with CONTENTIONS & REQUEST FOR A HEARING RE: LICENSE RENEWAL APPLICATION FOR INDIAN POINT 2 and INDIAN POINT 3

TABLE OF CONTENTIONS

CONTENTION 5: The Fire Protection Program described in the Current License Basis Documents including the unlawfully approved exemptions to Appendix R, the Safety Evaluation and the amended license for Indian Point 3 fail to adequately protect the health and safety of the public, and fail to meet the requirements of 10 CFR 50 and Appendix R

CONTENTION 6: Fire Protection Design Basis Threat. The Applicant's License Renewal Application fails to meet the requirements of 10 CFR54.4 "Scope," and fails to implement the requirements of the Energy Policy Act of 2005.

CONTENTION #7: Fire initiated by a light airplane strike risks penetrating vulnerable structures.

CONTENTION 8: The NRC improperly rushed approval Entergy's modified exemption request reducing fire protection standards from 1 hour to 24 minutes while deferring necessary design modifications.

CONTENTION 9: In violation of promises made to Congress the NRC did not correct deficiencies in fire protection, and instead have reduced fire protection by relying on manual actions to save essential equipment.

CONTENTION 10: (Unit 2) Cable separation for Unit 2 is non-compliant, fails to meet separation criteria and fails to meet Appendix R criteria. This has been a known issue since 1976; and again in 1984, yet remains non-compliant today.

CONTENTION 11A (Unit 2 and Unit 3): The Fire protection program as described on page B-47 of the Appendix B of the Applicant's LRA does not include fire wrap or cable insulation as part of its aging management program.

CONTENTION 11B: Environmental Impact of an increase in risk of fire damage due to degraded cable insulation is not considered thus the Applicants' LRA is incomplete and inaccurate, and the Safety Evaluation supporting the SAMA analysis is incorrect.

CONTENTION 12: Entergy either does not have, or has unlawfully failed to provide the Current License Basis' (CLB) for Indian Point 2 and 3, accordingly the NRC must license renewal.

CONTENTION 13: The LRA is incomplete and should be dismissed, because it fails to present a Time Limiting Aging Analysis and an Adequate Aging Management Plan, and instead makes vague commitments to manage the aging of the plant at uncertain dates in the future, thereby making the LRA a meaningless and voidable "agreement to agree."

CONTENTION 14: The LRA submitted fails to include Final License Renewal Interim Staff Guidance. For example, LR-ISG 2006-03, " Staff guidance for preparing Severe Accident Mitigation Alternatives."

CONTENTION 15: Regulations provides that in the event the NRC approves the LRA, then old license is retired, and a new superseding license will be issued, as a matter of law § 54.31. Therefore all citing criteria for a new license must be fully considered including population density, emergency plans and seismology.

CONTENTION 16: An Updated Seismic Analysis for Indian Point must be Conducted and Applicant must Demonstrate that Indian Point can avoid or mitigate a large earthquake. Indian Point Sits Nearly on Top of the Intersection of Two Major Earthquake belts,

CONTENTION 17: The population density within the 50 mile Ingestion Pathway EPZ of Indian Point is over 21 million, the population within in the 10 mile plume exposure pathway EPZ exceeds 500,000.

CONTENTION #18 Emergency Plans and evacuation plans for the four counties, surrounding are inadequate to protect public health and safety, due to limited road infrastructure, increased traffic and poor communications.

CONTENTION: #19 Security Plans Stakeholders contend that the way the force-on-force (FOF) tests are conducted do not prove that the Indian Point security force is capable to defend the facility against a credible terrorist attack or sabotage. The LRA does not address how Security, as required under section 10 CFR 100.12(f) and 10 CFR Part 73, will be managed during the proposed additional 20 years of operation against sabotage/terrorist forces with increasing access to sophisticated and advance weapons.

CONTENTION # 20: The LRA does not satisfy the NRC's underlying mandate of Reasonable Assurance of Adequate Protection of Public Health and Safety.

CONTENTION #21: Intentionally Omitted

CONTENTIONS 22-26 Indian Point was not required to comply with federally approved General Design Criteria, which constitutes a clear and flagrant violation of the Administrative Procedures Act, and Entergy's LRA fails to remediate the error, leaving Indian Point without adequate safety margins and the New York Metropolitan region without adequate assurance of protection of public health and safety

CONTENTION # 27: The LRA for Indian Point 2 & Indian Point 3 is insufficient in managing the environmental Equipment Qualification required by federal rules mandated that are required to mitigate numerous design basis accidents to avoid a reactor core melt.

Contention #28 - 32 The License's ineffective Quality Assurance Program violates fundamental independence requirements of Appendix B, and its ineffectiveness furthermore triggered significant cross cutting events during the past eight months that also indicate a broken Corrective Action Program, and failure of the Design Control Program, and as a result invalidate statements crediting these programs that are relied upon in the LRA.

CONTENTION #33: The EIS Supplemental Site Specific Report of the LRA is misleading and incomplete because it fails to include Refurbishment plans meeting the mandates of NEPA, 10 CFR 51.53 post-construction environmental reports and of 10 CFR 51.21. Issue Summary.

CONTENTION #34: Stakeholders contend that accidents involving the breakdown of certain in scope parts, components and systems are not adequately addressed Entergy's LRA for Indian Point 2 and Indian Point 3.

CONTENTION 35: Leak-Before-Break analysis is unreliable for welds associated with high energy line piping containing certain alloys at Indian Point 2 & Indian & Indian Pont 3.

CONTENTION #36: Entergy's License Renewal Application Does Not Include an Adequate Plan to Monitor and Manage Aging of Plant Piping Due to Flow-Accelerated Corrosion During the Period of Extended Operation.

CONTENTION 37: The LRA and the UFSAR's for Indian Point inadequately address the currently existing (known and unknown) environmental affects and aging degradation issues of ongoing leaks, and fail to lay out workable aging management plans for leaks and critical safety systems

CONTENTION #38: Microbial action potentially threatens all the stainless steel components, pipes, filters and valves at Indian Point (issue 99 of EIS)

CONTENTION #39: Indian Point 1 leaks constitute a violation of SafeStor and since components of IP1 are used in the operation of Indian Point 2, the LRA's failure to address these leaks and the interfacing IP 1-IP2 systems renders the LRA inaccurate, incomplete, and invalid

CONTENTION 40 : The LRA submitted fails to include Final License Renewal Interim Staff Guidance. For example, LR-ISG 2006-03, " Staff guidance for preparing Severe Accident Mitigation Alternatives."

CONTENTION # 41 : Entergy's high level, long-term or permanent, nuclear waste dump on the bank of the Hudson River.

CONTENTION # 42: Dry Cask Storage (Issue 83)
The Independent Spent Fuel Storage Installation (SFSI) being constructed at Indian Point for the purpose of holding the overflow of nuclear waste on site for decades, and probably more than a century, must be fully delineated and addressed in the aging management plan and, moreover constitutes an independent licensing issue.

CONTENTION 43: The closure of Barnwell will turn Indian Point into a low level radioactive waste storage facility, a reality the GEIS utterly fails to address, and a fact which warrants independent application with public comment and regulatory review.

CONTENTION 44 : The Decommissioning Trust Fund is inadequate and Entergy's plan to mix funding across Unit 2, 1 and 3 violates commitments not acknowledged in the application and 10 CFR rule 54.3.

CONTENTION 45 **Non-Compliance with NYS DEC Law – Closed Cycle Cooling "Best Technology Available" Surface Water Quality, Hydrology and Use (for all plants)**

CONTENTION 46: OMIT

CONTENTION 47: The Environmental Report Fails to Consider the Higher than Average Cancer Rates and Other Health Impacts in Four Counties Surrounding Indian Point.

CONTENTION 48 : Environmental Justice - Corporate Welfare

CONTENTION 49: Applicant's LRA fails to consider the effects of global warming and Applicant has failed to present a plan for how it will either analyze or manage such effects during an additional 20 years of operation.

CONTENTION 50: Failure to Address Environmental Impacts of Intentional Attacks & Airborne Threats

CONTENTION 51: Withholding of Access Proprietary Documents Impedes Stakeholders Adequate Review of Entergy Application for License Renewal of IP2 LLC and IP3 LLC.

Figure 2 Organization Chart - Post Reorganization

Attachment 1 General Corporate information

Attachment 2 Projected Balance Sheet

Attachment 3 Projected Income Statements, Non-Proprietary Version

Attachment 4 Affidavit of Michael Kansler

Attachment 5 Form of Support Agreement

Exhibit U
Omitted

Exhibit V
Synapse Financial Insecurity p1-40

Exhibit W
Corp Watch: Entergy Holds New Orleans Hostage

EXHIBIT X
Memorandum to Chairman Diaz April 25, 2003 NRC Enforcement of Regulatory Requirements . NRC Enforcement Regulatory Requirements and Commitments at Indian Point, Unit 2

Case No. 01-01 S.

EXHIBIT Y
Status of Decommissioning Funding for Plants Operated by Entergy Nuclear Operations, March 25, 2005. 10CFR50.7a5(f)(1)

EXHIBIT Z
Federal Register, August 1, 2007 Notice of Docketing of Application for Renewal.

EXHIBIT AA
H.R. 994: To Require the NRC to conduct an ISA

EXHIBIT BB
Notice of Availability of the Final License Renewal Interim Staff Guidance and Staff Guidance for Preparing Severe Accident Mitigation Alternatives Analysis. Aug. 14, 2007

EXHIBIT CC

NRC Regulatory Issue Summary 2003-09 Environmental Qualification of Low-Voltage Instrumentation and Control Cables. May 2, 2003

EXHIBIT DD

Entergy Replacement Reactor Vessel Head. Doosan Heavy Industries Co. Ltd.

EXHIBIT EE

CIECP: NRC Proposed Rule: Power Reactor Security Requirements 3/27/07

CRS Report for Congress- Nuclear Power Plant Vulnerability to Terrorist Attack

EXHIBIT FF

Omitted

EXHIBIT GG.1

Declaration of U. Witte: Review of Contention 14: Safety/Aging Mgmt

EXHIBIT HH

NYS Notice t Intervene in Petition

EXHIBIT II.2

Declaration of U. Witte: Review of Contention 35: Leak Before Break

EXHIBIT JJ

Entergy Questionairre 7/31/06: Groundwater Protection Baseline Info IPEC 1,2, & 3

EXHIBIT KK

Indian Point 2 2Q/2007 Plant Inspection Findings

EXHIBIT LL

Declaration of Dr. Gordon Thompson in Support of Petitioner's Concern

EXHIBIT MM

Gordon Thompson: Robust Storage of Spent Nuclear Fuel

EXHIBIT NN

Population Growth in Rockland, Orange, Putnam, Westchester 1960-2006

EXHIBIT OO

James Lee Witt Assoc.-Executive Summary : Review of Emergency Preparedness IP/Millstone, 2003.

EXHIBIT PP
POGO on Nuclear Security Act

EXHIBIT QQ
Levitan Study Executive Summary

EXHIBIT RR
NAS Report 2006: Replacement Energy of Indian Point
Executive Summary

EXHIBIT SS
Notes from 8/30/07 conference call regarding Dry Cask Storage at IP

EXHIBIT TT
Public Health Risks of Extending Licenses of the IP2 and 3 Nuclear Reactors,
10/6/07 Dr. Joe Mangano, Radiation and Public Health Project.0

EXHIBIT UU
Expert Witness - J. Mangano - Declaration

EXHIBIT VV
Intentionally Omitted

EXHIBIT WW
GAO -04-654 Nuclear Regulations: NRC's Liability Insurance

EXHIBIT XX
Replacement Energy for Indian Point: How Much Do We Need?

EXHIBITYY
Blank

EXHIBIT ZZ
Blank

EXHIBIT AAA
Declaration Connie Coker

EXHIBIT BBB
Janet Burnet

EXHIBIT CCC
Andrew Stewart

EXHIBIT DDD
Michel Lee

EXHIBIT EEE
Susan Shapiro

EXHIBIT FFF
Robert Jones

EXHIBIT GGG
Maureen Ritter

EXHIBIT HHH
New York City Councilman Vaca

EXHIBIT III
Dorice Madronero

EXHIBIT JJJ
Quality Control – Whistleblower letter

FIRE PROTECTION EXHIBITS 1 -20

Table of Fire Protection Exhibits

Exhibit number	Document	Comments
Exhibit FP No. 1	The Associated Press March 3, 1993, Wednesday, AM cycle Problems With Fire-Retarding Material Went Uncorrected, Panel Told **BYLINE:** By H. JOSEF HEBERT, Associated Press Writer States News Service March 3, 1993, Wednesday CONGRESSIONAL PANEL SAYS AREA NUCLEAR POWER PLANTS MAY EMPLOY DEFECTIVE FIRE RETARDANTS: Protectant Supposed To Aid In Emergency Shutdowns **BYLINE:** By Jennifer Babson, States News Service	These are two separate news reports
Exhibit FP No. 2	**OIG Report "ADEQUACY OF NRC STAFF'S ACCEPTANCE AND'REVIEW OF THERMO-LAG 330-1 FIRE BARRIER MATERIAL" Case no 91-04N, dated 8/12/1992**	
Exhibit FP No. 3	Environment and Energy Daily October 4, 2001 NUCLEAR SECURITY LANGUAGE FOR ANTI-TERRORISM BILL APPROVED **BYLINE:** Suzanne Struglinski **SECTION:** NUCLEAR POLICY; Vol. 10, No. 9	
Exhibit FP No. 4	Omitted	
Exhibit FP No. 5	Entergy Letter dated July 24, 2006 Re: Indian Point Unit NO.3 Docket No. 50-286 NL-06-078Request for Revision of Existing Exemptions from 10 CFR 50,	

Table of Fire Protection Exhibits

Exhibit number	Document	Comments
	Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2	
Exhibit FP No. 6	Indian Point Energy Center 450 Broadway, GSB P.O. Box 249 Buchanan, NY 10511-0249 Tel 914 734 6700 Fred Dacimo Site Vice President Administration August 16, 2007 Re: Indian Point Unit NO.3 Docket No. 50-286 NL-07-084 SUBJECT: Supplement to the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ElN-4 and PAB-2 for Indian Point Nuclear Generating Unit No.3 (lAC No. MD2671)	
Exhibit FP No. 7	First Declaration of Ulrich Witte	
Exhibit FP No. 8	**NUCLEAR REGULATORY COMMISSION** REGION I 475 ALLENDALE ROAD KING OF PRUSSIA. PENNSYLVANIA 19406-1415 May 11, 1995 New York Power Authority Indian Point 3 Nuclear Power Plant Post Office Box 215 Buchanan, NY 10511 SUBJECT: SPECIAL INSPECTION TO RESTART ITEMS, INSPECTION	

Table of Fire Protection Exhibits

Exhibit number	Document	Comments
	REVIEW FIRE PROTECTION AND APPENDIX R Inspection REPORT NO. 50-286195-81	
Exhibit FP No. 9	Updated FSAR Chapter 7 provided with renewal application	
Exhibit FP No. 9	Second Part Drawing that is referenced on Page 8 of this document	
Exhibit FP No. 9	Third part -- Drawing – 392-F-31193	Very large scale. This may not print well in hard copy. Suggest electronic version for adequate viewing.
Exhibit FP No. 10	REPORT ON THE NUCLEAR REGULATORY COMMISSION REACTOR SAFETY REVIEW PROCESS By Robert D. Pollard Project Manager Division of Project Management U. S. Nuclear Regulatory Commission February 6, 1976	
Exhibit FP No. 11	UNITED STATES NUCLEAR REGULATORY COMMISSION OFFICE OF NUCLEAR REACTOR REGULATION OFFICE OF NUCLEAR MATERIAL SAFETY AND SAFEGUARDS WASHINGTON D.C. 20555-0001 April 1, 2005 INFORMATION NOTICE 2005-07: RESULTS OF HEMYC ELECTRICAL RACEWAY FIRE BARRIER SYSTEM FULL SCALE FIRE TESTING	
Exhibit FP No. 12	December 9, 2003 POGO Letter to NRC Chairman Nils Diaz	

Table of Fire Protection Exhibits

Exhibit number	Document	Comments
Exhibit FP No. 13	CRS Report for Congress Received through the CRS Web Order Code RS21131 Updated August 9, 2005 **Nuclear Power Plants:** **Vulnerability to Terrorist Attack** Carl Behrens and Mark Holt Specialists in Energy Policy Resources, Science, and Industry Division	
Exhibit FP No. 14	March 27, 2007 Re: NRC Proposed Rule: Power Reactor Security Requirements (RIN 3150-AG63) Annette Vietti-Cook, Secretary U.S. Nuclear Regulatory Commission Washington, DC 20555-0001 Attn: Rulemakings and Adjudications Staff Submitted via e-mail to SECY@nrc.gov **COUNCIL ON INTELLIGENT ENERGY & CONSERVATION POLICY (CIECP) COMMENTS TO PROPOSED RULE 10 CFR PARTS 50, 72 AND 73 REGARDING POWER REACTOR SECURITY REQUIREMENTS AT LICENSED NUCLEAR FACILITIES**	
Exhibit FP No. 15	CRS Report for Congress Received through the CRS Web Order Code RS21131 Updated August 9, 2005 **Nuclear Power Plants:** **Vulnerability to Terrorist Attack** Carl Behrens and Mark Holt Specialists in Energy Policy Resources, Science, and Industry Division	Identical to 13
Exhibit FP No. 16	NUREG-1852 **Demonstrating the Feasibility and Reliability of**	

Table of Fire Protection Exhibits

Exhibit number	Document	Comments
	Operator Manual Actions in Response to Fire **Final Report** **U.S. Nuclear Regulatory Commission** **Office of Nuclear Regulatory Research** **Washington, DC 20555-0001**	
Exhibit FP No. 17	omitted	
Exhibit FP No. 18	omitted	
Exhibit FP No. 19	omitted	
Exhibit FP No. 20	SUE W. KELLY 19Tm DISTRICT. NEW YORK COMMITTEE ON FINANCIAL SERVICES, VICE CHAIR CHAIRWOMANS. UBCOMMITTEOEN OVERSIGHATN D INVESTIGATIONS **SUBCOMMITTE ON FINANCIAL IN STITUTIONS** Letter to Chairman Nils Diaz dated September 24, 2004	

EXHIBIT J

Mrs. Beck

DOCKET NUMBER PR-50
PROPOSED RULE
General Design Criteria

ATOMIC INDUSTRIAL FORUM INC.

850 THIRD AVENUE · NEW YORK, N.Y. 10022 · PLAZA 4-1075

October 2, 1967

DOCKETED
USAEC
OCT 4 1967
Office of the Secretary
Public Proceedings
Branch

Secretary
U.S. Atomic Energy Commission
Washington, D.C. 20545

Dear Sir:

Pursuant to notice which appeared in the Federal Register of July 11, 1967, the Forum Committee on Reactor Safety is pleased to forward the enclosed comments on AEC's proposed "General Design Criteria for Nuclear Power Plant Construction Permits".

These comments, which in a number of instances take the form of a redraft of the proposed criteria, are based on information developed during an August 9 meeting of the Committee. They have been further refined by a Committee task force comprised of the following members: Wallace Behnke of Commonwealth Edison Company; Arthur C. Gehr of Isham, Lincoln & Beale; R. J. McWhorter of General Electric Company; J. E. Tribble of Yankee Atomic Electric Company; Robert A. Wiesemann of Westinghouse Electric Corporation; and Edwin A. Wiggin of the Forum staff.

The comments have subsequently been circulated to those additional members of the Committee who participated in the August 9 meeting. It may, therefore, be concluded that the enclosed comments generally represent the views of the following additional Committee members:

R. H. Bielecki, Pennsylvania Power & Light Company
Warren S. Brown, Dilworth, Secord, Meagher & Associates, Ltd.
Harvey F. Brush, Bechtel Corporation
Robert W. Davies, Baltimore Gas and Electric Company
William S. Farmer, Allis-Chalmers Manufacturing Company
George C. Freeman, Jr., Hunton, Williams, Gay, Powell & Gibson
Robert E. Kettner, Consumers Power Company
R. W. Kupp, S. M. Stoller Associates
C. A. Larson, Consolidated Edison Company of New York, Inc.
Zelvin Levine, Hittman Associates, Inc.
James V. Neely, Jersey Central Power and Light Company
H. C. Ott, Ebasco Services, Inc.
Joseph W. Ray, Battelle Memorial Institute
Glenn A. Reed, Wisconsin Electric Power Company
Marlin Remley, Atomics International, Inc.
Royce J. Rickert, Combustion Engineering, Inc.

C/3

W. N. Thomas, Virginia Electric and Power Company
Robert E. Wascher, The Babcock & Wilcox Company
Samuel Zwickler, Burns & Roe, Inc.

Although these comments have been throughly reviewed by those individuals listed above, it should be understood that they do not necessarily represent a unanimity of opinion on all the criteria. Members of the Committee who participated in the August 9 discussion, particularly those who find themselves at variance with the views expressed herein, have been urged to make their views known directly to the AEC in behalf of their own respective companies and organizations.

Perhaps a further note of explanation on the enclosed comments is in order.

In the Committee's opinion, the proposed criteria are appreciably better organized than those initially suggested in November 1965. We have also noted with appreciation that some of the Committee's suggestions on the earlier criteria have been accommodated in the criteria now proposed.

The Committee believes that the principal objectives of the criteria should be to assist in the design of nuclear power plants, the preparation of applications for construction permits and operating licenses therefor and regulatory review of these applications to determine if such plants can be constructed and operated without undue risk to the health and safety of the public. The Committee further believes that these objectives should be explicitly stated and that they can be most effectively attained by writing the criteria to the extent possible as performance specifications.

We recommend that the following paragraph be added to the introduction - possibly following the last paragraph of the introduction as it appeared in the Federal Register notice:

> "Each of the requirements stated and implied in the criteria is premised on assuring that the nuclear power plant will be designed, constructed and operated in such a manner as not to cause undue risk to the health and safety of the public from radiation or the release of radioactive materials. To facilitate compliance with the requirements contained in the criteria, the criteria are presented to the extent possible, as performance specifications."

The Committee further believes that the introduction to the criteria should make more explicit reference to their intended direct applicability to water reactors in contrast to their only indirect applicability to reactors of other types, including fast breeders.

Some members of the Committee have noted the desirability and advantages of publishing these criteria as a guide rather than as an appendix to 10 CFR 50. They point out that, as a guide, their interpretation, application and refinement could be more easily adapted to a rapidly

If questions arise in reviewing these comments, the members of the task force would be pleased to meet with representatives of the AEC regulatory staff.

Sincerely,

Edwin A. Wiggin

Edwin A. Wiggin
Committee Secretary

EAW:epb
Enclosure

Comments of Forum Committee on Reactor Safety
on
AEC's Proposed Construction Permit Criteria

CRITERION 1 - QUALITY STANDARDS (Category A)

Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences, of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required.

> In the first sentence we have modified "accidents" with "nuclear" and substituted the phrase "cause undue risk to the health and safety of the public" to more precisely reflect what we believe was the AEC's intent. In the last sentence of the original draft, we have dropped the word "sufficiency" since we do not believe that it should be the responsibility of the applicant to document this unless the sufficiency of some specific item is in question. If for any reason the AEC questions the adequacy or sufficiency of a code or standard, it should take this matter up with the appropriate code drafting committee. Note that we have added a sentence requiring a showing of adequacy where there is no applicable code. The balance of the suggested changes are editorial in nature.

CRITERION 2 - PERFORMANCE STANDARDS (Category A)

Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear

accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

> The changes in the first sentence are in line with those suggested for Criterion 1. We have deleted the word "additional" on the premise that it is not reasonable to ask the applicant to consider the simultaneous or cumulative forces of more than one extraordinary natural phenomenon.

CRITERION 3 - FIRE PROTECTION (Category A)

A reactor facility shall be designed such that the probability of events such as fires and explosions and the potential consequences of such events will not result in undue risk to the health and safety of the public. Noncombustible and fire resistant materials shall be used throughout the facility wherever necessary to preclude such risk, particularly in areas containing critical portions of the facility such as containment, control room, and components of engineered safety features.

> These changes are consistent with the objective of assuring that there will be no undue risk to the health and safety of the public.

CRITERION 4 - SHARING OF SYSTEMS (Category A)

Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public.

As originally drafted, this criterion made unacceptable any impairment of safety, whether the impairment was significant or insignificant. This is unreasonable. Some impairment will undoubtedly result from almost any sharing but the impairment may not be significant enough to preclude the sharing. The test should be whether the sharing will result in undue risk to the health and safety of the public.

CRITERION 5 - RECORDS REQUIREMENTS (Category A)

The reactor licensee shall be responsible for assuring the maintenance throughout the life of the reactor of records of the design, fabrication, and construction of major components of the plant essential to avoid undue risk to the health and safety of the public.

Some of the records that should be maintained may or may not be under the physical control of the licensee or operator. He can, however, assure that they are maintained, by contractual arrangements, if necessary. Those records which are important are those which could have some bearing on the health and safety of the public.

CRITERION 6 - REACTOR CORE DESIGN (Categories A & B)

The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated.

We assume that "acceptable fuel damage limits" will be based on "undue risk to the health and safety of the public", not on economic grounds. The latter consideration is a matter for the licensee to decide. Further, these limits will depend on the circumstances leading to the damage. The example "transient situations" have been deleted since they may not be applicable in certain cases and they might also tend to prejudice design innovations.

CRITERION 7 - SUPPRESSION OF POWER OSCILLATIONS (Category B)

The design of the reactor core with its related controls and protection systems shall ensure that power oscillations, the magnitude of which could

cause damage in excess of acceptable fuel damage limits, are not possible or can be readily suppressed.

See comment on Criterion 6 with respect to "acceptable fuel damage limits".

CRITERION 8 - OVERALL POWER COEFFICIENT (Category B)

We recommend deletion of this criterion since it is not applicable to certain reactor types. It is possible for the overall power coefficient resulting from a sum of components with different time constants to be positive without causing any serious safety problem. For example, in a sodium graphite reactor the coefficient has a prompt negative component together with a positive component with a long time constant. This results in an overall positive coefficient, but the negative part of the coefficient is large enough and fast enough to assure satisfactory control and safety. Safety problems relating to reactivity considerations are adequately covered in Criteria 6 and 7.

CRITERION 9 - REACTOR COOLANT PRESSURE BOUNDARY (Category A)

The reactor coolant pressure boundary shall be designed, fabricated and constructed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime.

It is important to characterize the leakage as "uncontrolled". Our only other suggested change is insertion of the word, "fabricated".

CRITERION 10 - REACTOR CONTAINMENT (Category A)

Reactor containment shall be provided. The containment structure shall be designed (a) to sustain without undue risk to the health and safety of the public the initial effects of gross equipment failures, such as a large reactor coolant pipe break, without loss of required integrity and (b) together with other engineered safety features as may be necessary, to retain for as long as the situation requires the functional capability of the containment to the extent necessary to avoid undue risk to the health and safety of the public.

To avoid any ambiguity, "containment" should be characterized as "reactor containment". The statutory requirement of the licensee and the AEC is "to avoid undue risk to the health and safety of the public", not "to protect the public". It would

be helpful to cross reference this criterion to Criterion 37 to indicate what the AEC means by "engineered safety features". Consistent with our comments on Criterion 37, we have substituted "pipe" for "boundary" on the premise that an applicant should not be required to consider a design basis accident more conservative than the instantaneous double-ended, circumferential rupture of a large coolant pipe.

CRITERION 11 - CONTROL ROOM (Category B)

The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel.

As originally drafted, this criterion could be interpreted as requiring a second control room. Not only would such a requirement be inconsistent with current practice, we believe that the complexities introduced could adversely affect overall plant safety. We believe it possible to design and equip a control room to assure continuous occupancy under all circumstances, including fire. We have deleted reference to 10 CFR 20 since the radiation exposure limits set forth therein apply to normal operating conditions, not accident conditions. Compliance with the radiation exposure limits of 10 CFR 20 under accident or post-accident circumstances is neither necessary nor reasonable. We have deleted the last sentence of the original draft since it is unnecessary and contradictory with the requirement of continuous occupancy of the control room.

CRITERION 12 - INSTRUMENTATION AND CONTROL SYSTEMS (Category B)

Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables.

We have modified this criterion to more accurately and precisely reflect its intent.

CRITERION 13 - FISSION PROCESS MONITORS AND CONTROLS (Category B)

Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core.

> We have dropped the two examples since they are measures of reactivity rather than the fission process.

CRITERION 14 - CORE PROTECTION SYSTEMS (Category B)

Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

> We have deleted the phrase "act automatically" since manual action will prove adequate, indeed desirable, in some instances.

CRITERION 15 - ENGINEERED SAFETY FEATURES PROTECTION SYSTEMS (Category B)

> No change suggested.

CRITERION 16 - MONITORING REACTOR COOLANT LEAKAGE (Category B)

Means shall be provided to detect significant uncontrolled leakage from the reactor coolant pressure boundary.

> We have assumed the intent of this criterion is to assure that leakage from the primary system will be detected, not that the entire reactor coolant pressure boundary will be monitored. The latter requirement would be inconsistent with current practice and unnecessary. Also, consistent with Criterion 9, we believe that the leakage should be characterized as significant and uncontrolled.

CRITERION 17 - MONITORING RADIOACTIVITY RELEASES (Category B)

Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive.

We believe that the modified language as indicated above more accurately and precisely reflects the intent of the criterion.

CRITERION 18 - MONITORING FUEL AND WASTE STORAGE (Category B)

Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels.

We believe that the modified language as indicated above more accurately and precisely reflects the intent of the criterion.

CRITERION 19 - PROTECTION SYSTEMS RELIABILITY (Category B)

Protection systems shall be designed for high functional reliability and in-service testability necessary to avoid undue risk to the health and safety of the public.

The suggested change is in line with our comment on Criterion 1.

CRITERION 20 - PROTECTION SYSTEMS REDUNDANCY AND INDEPENDENCE (Category B)

Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served.

The significant change we have made here is to delete the last sentence of the original draft. It would appear preferable to provide duplicates of the best system or component rather than going to an inferior system or component based on a different principle.

CRITERION 21 - SINGLE FAILURE DEFINITION (Category B)

We recommend deletion of this criterion since it is more of a definition than a criterion and since the implied requirement is adequately covered by Criterion 23.

CRITERION 22 - SEPARATION OF PROTECTION AND CONTROL INSTRUMENTATION SYSTEMS (Category B)

This criterion should be deleted inasmuch as its requirements, to the extent they should be included in general criteria, [illegible] adequately covered by Criterion 20

CRITERION 23 - PROTECTION AGAINST MULTIPLE DISABILITY FOR PROTECTION SYSTEMS (Category B)

The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function or shall be tolerable on some other basis.

The suggested change here includes adding to the criterion the phrase, "or shall be tolerable on some other basis".

CRITERION 24 - EMERGENCY POWER FOR PROTECTION SYSTEMS (Category B)

We recommend deletion of this criterion since it would appear preferable to focus all requirements for emergency power in Criterion 39. Note that "protection systems" has been incorporated in Criterion 39 to accommodate this deletion.

CRITERION 25 - DEMONSTRATION OF FUNCTIONAL OPERABILITY OF PROTECTION SYSTEMS (Category B)

Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred.

The reason for the changes here is that the licensee should be given some latitude in determining when and how such tests should be carried out. Further, he should be required only to test the active components of a protection system in contrast, for example, to a rupture diaphragm which could only be tested at the expense of destroying it. Also, certain tests might permit the licensee to determine if failure or loss of redundancy has occurred, but they might not permit him to demonstrate it.

CRITERION 26 - PROTECTION SYSTEMS FAIL-SAFE DESIGN (Category B)

No change suggested.

CRITERION 27 - REDUNDANCY OF REACTIVITY CONTROL (Category A)

Two independent reactivity control systems, preferably of different principles, shall be provided.

The phrase, "At least" which prefaced the original criterion suggests a possible escalation of requirements which we do not believe was intended.

CRITERION 28 - REACTIVITY HOT SHUTDOWN CAPABILITY (Category A)

The reactivity control systems provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition.

> Deletion of the preface phrase, "At least two of" is based on the comment made on Criterion 27. We have deleted the examples at the end of the original criterion since they could be interpreted to indicate a requirement for two fast reactivity shutdown mechanisms. This requirement is unnecessary when there is sufficient redundancy in one of the reactivity control systems to assure shutdown.

CRITERION 29 - REACTIVITY SHUTDOWN CAPABILITY (Category A)

One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn.

> Deletion of the preface phrase, "At least", is consistent with the comments on Criteria 27 & 28. The other editorial changes are for purposes of clarification.

CRITERION 30 - REACTIVITY HOLDOWN CAPABILITY (Category B)

The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public.

> Deletion of the preface phrase, "At least one of", is consistent with the comments on Criteria 27, 28 & 29. Further, the public health and safety will not be compromised by a return to low power.

CRITERION 31 - REACTIVITY CONTROL SYSTEMS MALFUNCTION (Category B)

The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by

limiting reactivity transients to avoid exceeding acceptable fuel damage limits.

> We believe the criterion should preserve its original objective and at the same time acknowledge that one of the functions of the reactor protection system is to protect against certain control system malfunctions.

CRITERION 32 - MAXIMUM REACTIVITY WORTH OF CONTROL RODS (Category A)

Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core.

> We believe substitution of "reasonable" for "considerable" and the substitution of "lose capability of cooling the core" for "impair the effectiveness of emergency core cooling" more precisely reflects the intent of the criterion. The re-wording also correctly implies that emergency core cooling will generally be required only if the reactor coolant pressure boundary is breached.

CRITERION 33 - REACTOR COOLANT PRESSURE BOUNDARY CAPABILITY (Category A)

The reactor coolant pressure boundary shall be capable of accommodating without rupture the static and dynamic loads imposed on any boundary component as a result of an inadvertent and sudden release of energy to the coolant. As a design reference, this sudden release shall be taken as that which would result from a sudden reactivity insertion such as rod ejection (unless prevented by positive mechanical means), rod dropout, or cold water addition.

> We have deleted the phrase, "and with only limited allowance for energy absorption through plastic deformation", on the premise that it is not helpful.

CRITERION 34 - REACTOR COOLANT PRESSURE BOUNDARY RAPID PROPAGATION FAILURE PREVENTION (Category A)

The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures. Consideration shall be given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.

The detailed requirements contained in the original version are not appropriate for general criteria.

CRITERION 35 - REACTOR COOLANT PRESSURE BOUNDARY BRITTLE FRACTURE PREVENTION (Category A)

With the re-writing of Criterion 34 as indicated above, this criterion can and should be deleted.

CRITERION 36 - REACTOR COOLANT PRESSURE BOUNDARY SURVEILLANCE (Category A)

Reactor coolant pressure boundary components shall have provisions for inspection, testing, and surveillance of critical areas by appropriate means to assess the structural and leaktight integrity of the boundary components during their service lifetime. For the reactor vessel, a material surveillance program conforming with current applicable codes shall be provided.

It should not be necessary to inspect or maintain surveillance over all portions of the coolant pressure boundary; hence, we have inserted the phrase, "of critical areas". We believe that both the applicant and the AEC are in a better position to take advantage of developing technology and code refinement if these general design criteria refer to "current applicable codes" rather than to specifically designated codes.

CRITERION 37 - ENGINEERED SAFETY FEATURES BASIS FOR DESIGN (Category A)

Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. Such engineered safety features shall be designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary assuming unobstructed discharge from both ends.

> Deletion of the phrase, "As a minimum", and substitution of "piping" for "pressure boundary" are both intended to eliminate the implication that the applicant should be required to consider a design accident basis more conservative than the instantaneous, double-ended, circumferential rupture of the largest pipe in the primary system. On this premise, retention of the original language introduces a vagueness which tends to defeat the objective of the criterion.

CRITERION 38 - RELIABILITY AND TESTABILITY OF ENGINEERED SAFETY FEATURES (Category A)

All engineered safety features shall be designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public.

> Avoiding undue risk to the health and safety of the public is the purpose of all engineered safety features and the "functional reliability and ready testability" of such features is directly related to their attainment of this objective. To tie this criterion to the problem of siting appears extraneous and not helpful; hence, we have deleted the second sentence.

CRITERION 39 - EMERGENCY POWER (Category A)

An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component.

> As originally drafted, this criterion could be interpreted as requiring two off-site and two on-site power sources. Since neither the AEC nor the licensee may have any control over

the off-site power supply and since an emergency on-site power supply adequate to meet the power needs of the engineered safety features is required, any reference to off-site power is irrelevant. We have, therefore, re-written this criterion to eliminate such reference to off-site power. We have also changed the title of the criterion to accommodate the addition of "protection systems", which reference was added because of the deletion of Criterion 24.

CRITERION 40 - MISSILE PROTECTION (Category A)

Adequate protection for those engineered safety features, the failure of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures.

The suggested changes in this criterion are for purposes of clarification.

CRITERION 41 - ENGINEERED SAFETY FEATURES PERFORMANCE CAPABILITY (Category A)

Engineered safety features such as the emergency core cooling system and the containment heat removal system shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public.

We believe the measure of "sufficient performance capability" of an engineered safety feature should be that no undue risk to the public health and safety will result from the failure of any single active component of that feature. The modified language, in our opinion, more accurately and precisely reflects the intent of the criterion.

CRITERION 42 - ENGINEERED SAFETY FEATURES COMPONENTS CAPABILITY (Category A)

Engineered safety features shall be designed so that the capability of these features to perform their required function is not impaired by the effects of a loss-of-coolant accident to the extent of causing undue risk to the health and safety of the public.

Although it would appear extremely difficult, if not impossible, to design engineered safety features in such a way that a loss-of-coolant accident will cause no impairment of the capability of any component or system, it is possible to design them to meet the requirements of this criterion as stated above.

CRITERION 43 - ACCIDENT AGGRAVATION PREVENTION (Category A)

Protection against any action of the engineered safety features which would accentuate significantly the adverse after-effects of a loss of normal cooling shall be provided.

> The intent here was simply to state the criterion in a more positive way.

CRITERION 44 - EMERGENCY CORE COOLING SYSTEM CAPABILITY (Category A)

An emergency core cooling system with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty.

> In our opinion, one emergency core cooling system which incorporates a sufficient redundancy of active components and covers the full range of postulated breaks should be adequate. Our modification of this criterion reflects this consensus. For this reason, we have omitted the last sentence of the original criterion.

CRITERION 45 - INSPECTION OF EMERGENCY CORE COOLING SYSTEM (Category A)

Design provisions shall where practical be made to facilitate physical inspection of all critical parts of the emergency core cooling system, including reactor vessel internals and water injection nozzles.

> Since inspection of water injection nozzles is not always possible on a reasonably complete and non-destructive basis and since the failure of a safety injection nozzle is assumed in most accident analyses, we have inserted the phrase, "where practical".

CRITERION 46 - TESTING OF EMERGENCY CORE COOLING SYSTEM COMPONENTS (Category A)

> No comment other than the criterion should be presented in the context of a single emergency core cooling system, consistent with the comments offered on Criterion 44.

CRITERION 47 - TESTING OF EMERGENCY CORE COOLING SYSTEM (Category A)

A capability shall be provided to test periodically the operability of the emergency core cooling system up to a location as close to the core as is practical.

> Testing the "operability" in contrast to the "delivery capability" of the emergency core cooling system "up to" rather than "at" a location close to the core more accurately reflects the art of the possible and should provide for as adequate a test of reliability.

CRITERION 48 - TESTING OF OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEM (Category A)

A capability shall be provided to test initially, under conditions as close as practical to design, the full operational sequence that would bring the emergency core cooling system into action, including the transfer to alternate power sources.

> The only change here, and a significant one we believe, is insertion of the word, "initially". Although we concur that a capability to test the operational sequence of the emergency core cooling system should be provided, the test as a practical matter would not be carried out frequently and possibly not more than once - prior to startup.

CRITERION 49 - REACTOR CONTAINMENT DESIGN BASIS (Category A)

The reactor containment structure, including access openings and penetrations, and any necessary containment heat removal systems shall be designed so that the leakage of radioactive materials from the containment structure under conditions of pressure and temperature resulting from the largest credible energy release following a loss-of-coolant accident, including the calculated energy from metal-water or other chemical reactions that could occur as a consequence of failure of any single active component in the emergency core cooling system, will not result in undue risk to the health and safety of the public.

> The objective of this criterion, in our opinion, should be that under the circumstances of an accident the integrity of the containment should be such as to prevent

Undue risk to the health and safety of the public. Since the maintenance of containment integrity is based on effective functioning of the emergency core cooling system, it appears unreasonable in this criterion to assume the complete failure of the emergency core cooling system; hence we have assumed a failure of a single active component. Consistent with this assumption, we believe that the pressure and temperature to be withstood should be characteristic of those anticipated from the largest credible energy release associated with a loss-of-coolant accident, including the calculated energy from metal-water and other chemical reactions. Acceptance of the "failure of a single active component" concept is consistent with Criterion 41.

CRITERION 50 - NDT REQUIREMENT FOR CONTAINMENT MATERIAL (Category A)

The selection and use of containment materials shall be in accordance with applicable engineering codes.

It appears to us that the specific requirements of this criterion as originally drafted are not in keeping with the intent of general design criteria.

CRITERION 51 - REACTOR COOLANT PRESSURE BOUNDARY OUTSIDE CONTAINMENT (Category A)

If part of the reactor coolant pressure boundary is outside the containment, features shall be provided to avoid undue risk to the health and safety of the public in case of an accidental rupture in that part.

It is our understanding that it is the responsibility of the licensee to "avoid undue risk to" rather than "to protect" the health and safety of the public. We have deleted the second sentence of the criterion as originally drafted on the premise that it is only incidental to the requirement set forth in the first sentence.

CRITERION 52 - CONTAINMENT HEAT REMOVAL SYSTEMS (Category A)

Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure this system shall perform its required function, assuming failure of any single active component.

Deletion of the phrase "at least" is consistent with our comment on Criterion 27. The other changes are consistent with our comments on Criterion 41.

CRITERION 53 - CONTAINMENT ISOLATION VALVES (Category A)

No change suggested.

CRITERION 54 - INITIAL LEAKAGE RATE TESTING OF CONTAINMENT (Category A)

Containment shall be designed so that integrated leakage rate testing can be conducted at the peak pressure calculated to result from the design basis accident after completion and installation of all penetrations and the leakage rate shall be measured over a sufficient period of time to verify its conformance with required performance.

> We have inserted "initial" in the title to differentiate Criterion 54 from Criterion 55. Further, we believe it more realistic to leak test at peak pressures associated with postulated accidents than at design pressure. Correlation of leakage rate tests at postulated accident pressures with those conducted at design pressure prior to installation of containment penetrations will permit extrapolation of observed leakage rates to design pressure conditions.

CRITERION 55 - PERIODIC CONTAINMENT LEAKAGE RATE TESTING (Category A)

The containment shall be designed so that an integrated leakage rate can be periodically determined by test during plant lifetime.

> Our suggested changes here are consistent with our comments on Criterion 54. Further, a requirement calling for periodic leak testing at design pressure would impose an unnecessary and impractical design requirement on the plant.

CRITERION 56 - PROVISIONS FOR TESTING OF PENETRATIONS (Category A)

Provisions shall be made to the extent practical for periodically testing penetrations which have resilient seals or expansion bellows to permit leak tightness to be demonstrated at the peak pressure calculated to result from occurrence of the design basis accident.

> We have inserted the word, "periodically" to avoid an interpretation that we do not believe was intended, namely a requirement for "continuous" testing. The other suggested change is consistent with our comments on Criteria 54 & 55.

CRITERION 57 - PROVISIONS FOR TESTING OF ISOLATION VALVES (Category A)

Capability shall be provided to the extent practical for testing functional operability of valves and associated apparatus essential to the containment function for establishing that no failure has occurred and for determining that valve leakage does not exceed acceptable limits.

> Our only suggested change here is insertion of "to the extent practical". We believe this is consistent with the intent of the criterion as originally drafted, but we also believe that the qualification should be explicit rather than implicit. This comment also applies to Criteria 58, 59, 60, 62, 63, 64 and 65.

CRITERION 58 - INSPECTION OF CONTAINMENT PRESSURE-REDUCING SYSTEMS (Category A)

> See comment on Criterion 57.

CRITERION 59 - TESTING OF CONTAINMENT PRESSURE-REDUCING SYSTEMS COMPONENTS (Category A)

> See comment on Criterion 57.

CRITERION 60 - TESTING OF CONTAINMENT SPRAY SYSTEMS (Category A)

A capability shall be provided to the extent practical to test periodically the operability of the containment spray system at a position as close to the spray nozzles as is practical.

> Insertion of the phrase, "to the extent practical" is consistent with our comment on Criterion 57. The basis for substitution of "operability" for "delivery capability" is the same as that used in our comments on Criterion 47.

CRITERION 61 - TESTING OF OPERATIONAL SEQUENCE OF CONTAINMENT PRESSURE-REDUCING SYSTEMS (Category A)

A capability shall be provided to test initially under conditions as close as practical to the design and the full operational sequence that would bring the containment pressure-reducing systems into action, including

CRITERION 62 - INSPECTION OF AIR CLEANUP SYSTEMS (Category A)

See comment on Criterion 57.

CRITERION 63 - TESTING OF AIR CLEANUP SYSTEMS COMPONENTS (Category A)

See comment on Criterion 57.

CRITERION 64 - TESTING OF AIR CLEANUP SYSTEMS (Category A)

See comment on Criterion 57.

CRITERION 65 - TESTING OF OPERATIONAL SEQUENCE OF AIR CLEANUP SYSTEMS (Category A)

See comment on Criterion 61.

CRITERION 66 - PREVENTION OF FUEL STORAGE CRITICALITY (Category B)

No change suggested.

CRITERION 67 - FUEL AND WASTE STORAGE DECAY HEAT (Category B)

Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities and to waste storage tanks that could result in radioactivity release which would result in undue risk to the health and safety of the public.

We have substituted "which would result in undue risk to the health and safety of the public" for "to plant operating areas or the public environs" since we believe the first phrase more accurately describes the responsibility of the licensee.

CRITERION 68 - FUEL AND WASTE STORAGE RADIATION SHIELDING (Category B)

Adequate shielding for radiation protection shall be provided in the design of spent fuel and waste storage facilities.

The suggested change permits the criterion to accommodate radiation limits as may be specified which may differ from those set forth in 10 CFR 20.

CRITERION 69 - PROTECTION AGAINST RADIOACTIVITY RELEASE FROM SPENT FUEL AND WASTE STORAGE (Category B)

Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity.

We have avoided the use of the word, "containment" because of its possible ambiguous connotation. The licensee may rely on some means other than containment to meet the requirements of the criterion. The other suggested changes are consistent with our comments on Criterion 67.

CRITERION 70 - CONTROL OF RELEASES OF RADIOACTIVITY TO THE ENVIRONMENT (Category B)

The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capacity shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control shall be justified (a) on the basis of 10 CFR 20 requirements for normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10 CFR 100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence.

We have deleted the qualification on condition (b) namely, "except that reduction of the recommended dosage levels may be required where high population densities or very large cities can be affected by the radioactive effluents". This qualification is not helpful and could be subject to misinterpretation by the uninformed public.

ATOMIC ENERGY COMMISSION

[10 CFR Parts 50, 115]

CODES AND STANDARDS FOR NUCLEAR POWER UNITS

Notice of Proposed Rule Making

The Atomic Energy Commission has under consideration amendments of its regulations in 10 CFR Part 50, "Licensing of Production and Utilization Facilities," and 10 CFR Part 115, "Procedures for Review of Certain Nuclear Reactors Exempted From Licensing Requirements," which would establish minimum quality standards for the design, fabrication, erection, construction, testing, and inspection of certain systems and components of boiling and pressurized water-cooled nuclear power reactor units by requiring conformance with appropriate editions of published industry codes and standards.

Criterion 1 of the "General Design Criteria for Nuclear Power Plant Construction Permits" (proposed Appendix A of Part 50) [1] states that systems and components of nuclear power plants which are essential to the prevention of accidents which could affect public health and safety or to mitigation of their consequences be designed, fabricated, and tested to quality standards that reflect the importance of the safety function to be performed. It has been generally recognized that for boiling and pressurized water-cooled reactors, pressure vessels, piping, valves and pumps which are part of the reactor coolant pressure boundary should, as a minimum, be designed, fabricated, inspected, and tested in accordance with the requirements of the applicable American Society of Mechanical Engineers (ASME) codes in effect at the time the equipment is purchased, and protection systems (electrical and mechanical sensors and associated circuitry) should, as a minimum, be designed to meet the criteria developed by the Institute of Electrical and Electronics Engineers (IEEE).

The ASME codes for pressure vessels, piping, pumps, and valves and the IEEE criteria for protection systems were developed and are revised periodically by industry code committees composed of representatives of utilities, reactor designers, architect-engineers, component manufacturers, insurance companies, the Commission, and others. New industry codes and revisions to existing codes generally do not become effective for at least a year after publication for trial use and comment, and only then for contracts entered into after the effective date. Because of the time delays between the execution of the contract for and start of design or fabrication of some reactor components, 2 years may elapse between the effective dates of new or revised codes and the application of their requirements to the design and fabrication of components. Even after components complying with these code requirements are fabricated, another 2 or 3 years may elapse before the reactor is operated. The effect of this traditional pattern is that the results of currently available improved codes will not be seen in operating reactors for many years hence.

Because of the safety significance of uniform early compliance by the nuclear industry with the requirements of these ASME and IEEE codes and published code revisions, the Commission is considering the adoption of amendments to Parts 50 and 115 to require that certain components of water-cooled reactors important to safety comply with these codes and appropriate revisions to the codes at the earliest feasible time. In such reactors for which construction permits have been issued but which have not been licensed for operation, such components would be required to comply with the codes in effect at the time the equipment was ordered. In reactors for which construction permits are issued on or after April 1, 1970, such components, regardless of order date, would be required to comply with the more recent revisions of the codes (excluding Code Cases) specified in the proposed amendments.

The various dates given in the proposed amendments for compliance with the new industry codes and standards have been selected to give approximately 3 months notice of the Commission's intent to require compliance, as a condition of licensing, with specified codes or addenda that now have been available to the industry for at least 6 months. In cases where the design or fabrication of some reactor components has proceeded to the point where compliance with the specified requirements, or portions thereof, would result in hardships or unusual difficulties without a compensating increase in the level of safety, the Commission would be authorized under § 50.55a(b)(1) to grant exceptions. It should also be noted that § 50.55a(b)(2) would permit the Commission to authorize deviations from the requirements of the specified codes and standards if it can be shown that an equivalent level of safety will be provided.

The Commission considers that a significant improvement in the level of quality in design, fabrication and testing of systems and components important to safety of each reactor will be afforded by compliance with the requirements of the more recent codes specified in the proposed amendments, or portions thereof, and encourages such compliance whenever practicable, regardless of the date of purchase of equipment or the provisions of these proposed amendments. Compliance with the provisions of the proposed amendments and the referenced codes is intended to insure a basic sound quality level. It may be that the special safety importance of a particular system or component will call for supplementary measures. If analysis of the system shows that such is the case, appropriate supplementary measures are expected to be adopted by applicants and licensees, or will be required by the Commission.

Pursuant to the Atomic Energy Act of 1954, as amended, and section 553 of title 5 of the United States Code, notice is hereby given that adoption of the following amendments to 10 CFR Parts 50 and 115 is contemplated. All interested persons who desire to submit written comments or suggestions for consideration in connection with the proposed amendments should send them to the Secretary, U.S. Atomic Energy Commission, Washington, D.C. 20545, Attention: Chief, Public Proceedings Branch, within 60 days after publication of the notice in the FEDERAL REGISTER. Comments received after that period will be considered if it is practicable to do so, but assurance of consideration cannot be given except as to comments filed within the period specified. Copies of comments received may be examined at the Commission's Public Document Room, 1717 H Street NW., Washington, D.C.

1. Paragraph (c) of § 50.55 is amended to read as follows:

§ 50.55 Conditions of construction permits.

Each construction permit shall be subject to the following terms and conditions:

* * * * *

(c) Except as modified by this section and § 50.55a, the construction permit shall be subject to the same conditions to which a license is subject.

* * * * *

2. A new § 50.55a is added to 10 CFR Part 50 to read as follows:

§ 50.55a Codes and standards.

Each construction permit for a utilization facility shall be subject to the following conditions, in addition to those specified in § 50.55:

[1] The General Design Criteria were published for public comment in the FEDERAL REGISTER on July 11, 1967 (32 F.R. 10213).

(a) Structures, systems, and components shall be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety function to be performed.

(b) As a minimum, the systems and components of boiling and pressurized water-cooled nuclear power reactors specified in paragraphs (c), (d), (e), and (f) of this section shall meet the requirements described in those paragraphs and the protection systems of nuclear power reactors of all types shall meet the requirements described in paragraph (g) of this section, except as authorized by the Commission upon demonstration by the applicant for or holder of a construction permit that:

(1) Design, fabrication, erection, testing, or inspection of the specified system or component is, to the maximum extent practical, in accordance with generally recognized codes and standards and has proceeded to a point prior to_____ _____* such that compliance with the described requirements or portions thereof would result in hardships or unusual difficulties without a compensating increase in the level of safety; or

(2) Proposed deviations from the described requirements or portions thereof will be compensated for by factors or design features which provide at least an equivalent level of safety.

(c) *Pressure vessels.* For construction permits issued before April 1, 1970, for reactors not licensed for operation, pressure vessels which are part of the reactor coolant pressure boundary shall meet the requirements set forth in Section III of the American Society of Mechanical Engineers (hereinafter referred to as ASME) Boiler and Pressure Vessel Code, Applicable Code Cases, and Addenda[1] in effect at the time the vessel was ordered. For construction permits issued on or after April 1, 1970, pressure vessels which are part of the reactor coolant pressure boundary shall meet the requirements for Class A vessels set forth in the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code (excluding Code Cases), the Summer 1968 Addenda and the Winter 1968 Addenda dated June 30, and December 31, 1968, respectively, and the Summer 1969 Addenda dated June 30, 1969.[1]

(d) *Piping.* For construction permits issued before April 1, 1970, for reactors not licensed for operation, piping, and fittings which are part of the reactor coolant pressure boundary shall, if ordered before July 26, 1967, meet the requirements set forth in the American Standard Code for Pressure Piping (ASA B31.1—1955), applicable Code Cases and Addenda in effect at the time the piping or fitting was ordered, and the requirements set forth in ASA B31 Code Cases N7, N9, and N10[1] or if ordered after July 26, 1967, meet the requirements set forth in the Power Piping Section of the USA Standard Code for Pressure Piping (USAS B31.1.0—1967) applicable Code Cases, and Addenda in effect at the time the piping or fitting was ordered, and the requirements set forth in ASA B31 Code Cases N7, N9, and N10.[1] For construction permits issued on or after April 1, 1970, piping and fittings which are part of the reactor coolant pressure boundary shall meet the requirements for Class I piping set forth in the draft Nuclear Power Piping Section of the USA Standard Code for Pressure Piping (USAS B31.7), dated February 1968 (excluding Code Cases), and Errata dated June 1968, the requirements set forth in Appendix IX—Quality Control and Nondestructive Examination Methods, of the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code, and the requirements set forth in paragraph N-153 in the Summer 1969 Addenda dated June 30, 1969, to the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code.[1]

(e) *Pumps and valves.* For construction permits issued before April 1, 1970, for reactors not licensed for operation, pumps which are part of the reactor coolant pressure boundary shall meet the nondestructive testing requirements set forth in ASA B31 Code Cases N7, N9, and N10.[1] Valves which are part of the reactor coolant pressure boundary shall if ordered before July 26, 1967, meet the requirements set forth in the American Standard Code for Pressure Piping (ASA B31.1—1955), applicable Code Cases and Addenda in effect at the time the valve was ordered, and the requirements set forth in ASA B31 Code Cases N2, N7, N9, and N10[1] or if ordered after July 26, 1967, meet the requirements set forth in the Power Piping Section of the USA Standard Code for Pressure Piping (USAS B31.1.0—1967), applicable Code Cases, and Addenda in effect at the time the valve was ordered, and the requirements set forth in the ASA B31 Code Cases N2, N7, N9, and N10.[1] For construction permits issued on or after April 1, 1970, pumps and valves which are part of the reactor coolant pressure boundary shall meet the requirements for Class I pumps and valves set forth in the draft ASME Standard Code for Pumps and Valves for Nuclear Power, dated November 1968 (excluding Code Cases), the requirements set forth in Appendix IX—Quality Control and Nondestructive Examination Methods, of the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code, and the requirements set forth in paragraph N-153 in the Summer 1969 Addenda dated June 30, 1969 to the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code.[1]

(f) *Inservice inspection requirements.* For construction permits issued on or after April 1, 1970, pressure vessels, piping, fitting, pumps, and valves which are part of the reactor coolant pressure boundary shall meet the requirements set forth in the draft ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems, dated October 1968 (excluding Code Cases). The requirements of this paragraph need not be met by pressure-containing components whose rupture would not result in a loss of reactor coolant in excess of the replenishment capability and capacity of the normal makeup systems for the interval of time necessary to permit a reactor shutdown and orderly cooldown.

(g) *Protection systems.* For construction permits issued after April 1, 1970, protection systems shall meet the requirements set forth in the 1968 Edition of the Proposed Institute of Electrical and Electronics Engineers Criteria for Nuclear Power Plant Protection Systems (IEEE No. 279), dated August 1968.[2]

(h) *Reactor coolant pressure boundary.* As used in paragraphs (c), (d), (e), and (f) of this section, "reactor coolant pressure boundary" means all those pressure-containing components, such as pressure vessels, piping, pumps, and valves, within the following systems or portions of systems of boiling and pressurized water-cooled nuclear power reactors:

(1) The reactor coolant system. For a nuclear power reactor of the direct cycle boiling water type, the reactor coolant system extends to and includes the outermost containment isolation valves capable of external actuation* in the main steam and feedwater piping, and the reactor coolant system safety and relief valves.

(2) Portions of associated auxiliary systems connected to the reactor coolant system. For piping of these systems which penetrates primary reactor containment, the boundary extends to and includes the first containment isolation valve outside the containment capable of external actuation.* For piping of these systems which contains two valves, both of which are normally closed during normal reactor operation, the boundary extends to and includes the second of these valves (the second of which must be capable of external actuation*), whether or not the system piping penetrates primary reactor containment.

(3) Portions of the emergency core cooling system connected to the reactor coolant system. For piping of this system which penetrates primary reactor containment, the boundary extends to and includes the first containment isolation valve outside containment capable of external actuation.* For piping of this system which does not penetrate primary reactor containment, the boundary extends to and includes the second of two valves normally closed during normal reactor operation.

3. Paragraph (a) of § 115.43 is amended to read as follows:

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* Effective date of these amendments.

[1] Copies may be obtained from the American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, N.Y. 10017. Copies are available for inspection at the Commission's Public Document Room, 1717 H Street NW., Washington, D.C.

[2] A copy may be obtained from the Institute of Electrical and Electronics Engineers, United Engineering Center, 345 East 47th Street, New York, N.Y. 10017. A copy is available for inspection at the Commission's Public Document Room, 1717 H Street NW., Washington, D.C.

* Simple check valves are not acceptable for this purpose.

§ 115.43 Conditions of construction authorizations.

Each construction authorization shall be subject to the following terms and conditions.

(a) Except as modified by this section and § 115.43a, the construction authorization shall be subject to the same conditions to which an operating authorization is subject.

* * * * *

4. A new § 115.43a is added to 10 CFR Part 115 to read as follows:

§ 115.43a Codes and standards.

Each construction authorization shall be subject to the following conditions, in addition to those specified in § 115.43:

(a) Structures, systems, and components of nuclear reactors shall be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance to the safety function to be performed.

(b) As a minimum, the systems and components of boiling and pressurized water-cooled nuclear power reactors specified in paragraphs (c), (d), (e), and (f) of this section shall meet the requirements described in those paragraphs and the protection systems of nuclear power reactors of all types shall meet the requirements described in paragraph (g) of this section, except as authorized by the Commission upon demonstration by the applicant for or holder of a construction authorization that:

(1) Design, fabrication, erection, testing, or inspection of the specified system or component is, to the maximum extent practical, in accordance with generally recognized codes and standards and has proceeded to a point prior to ----------* such that compliance with the described requirements or portions thereof would result in hardships or unusual difficulties without a compensating increase in the level of safety; or

(2) Proposed deviations from the described requirements or portions thereof will be compensated for by factors or design features which provide at least an equivalent level of safety.

(c) *Pressure vessels.* For construction authorizations issued before April 1, 1970, for reactors not authorized for operation, pressure vessels which are part of the reactor coolant pressure boundary shall meet the requirements set forth in Section III of the American Society of Mechanical Engineers (hereinafter referred to as ASME) Boiler and Pressure Vessel Code, applicable Code Cases, and Addenda [1] in effect at the time the vessel was ordered. For construction authorizations issued on or after April 1, 1970, pressure vessels which are part of the reactor coolant pressure boundary shall meet the requirements for Class A vessels set forth in the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code (excluding Code Cases), the Summer 1968 Addenda and the Winter 1968 Addenda dated June 30, 1968, and December 31, 1968, respectively, and the Summer 1969 Addenda dated June 30, 1969.[1]

(d) *Piping.* For construction authorizations issued before April 1, 1970, piping and fittings which are part of the reactor coolant pressure boundary shall if ordered before July 26, 1967, meet the requirements set forth in the American Standard Code for Pressure Piping (ASA B31.1—1955), applicable Code Cases and Addenda in effect at the time the piping or fitting was ordered, and the requirements set forth in ASA B31 Code Cases N7, N9, and N10 [1] or if ordered after July 26, 1967, meet the requirements set forth in the Power Piping Section of the USA Standard Code for Pressure Piping (USAS B31.1.0—1967), applicable Code Cases and Addenda in effect at the time the piping or fitting was ordered, and the requirements set forth in ASA B31 Code Cases N7, N9, and N10.[1] For construction authorizations issued on or after April 1, 1970, piping and fittings which are part of the reactor coolant pressure boundary shall meet the requirements for Class I piping set forth in the draft Nuclear Power Piping Section of the USA Standard Code for Pressure Piping (USAS B31.7), dated February 1968 (excluding Code Cases) and Errata dated June 1968, the requirements set forth in Appendix IX—Quality Control and Non-destructive Examination Methods, of the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code, and the requirements set forth in paragraphs N-153 in the Summer 1969 Addenda dated June 30, 1969, to the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code.[1]

(e) *Pumps and valves.* For construction authorizations issued before April 1, 1970, for reactors not authorized for operation, pumps which are part of the reactor coolant pressure boundary shall meet the nondestructive testing requirements set forth in ASA B31 Code Cases N7, N9, and N10.[1] Valves which are part of the reactor coolant pressure boundary shall if ordered before July 26, 1967, meet the requirements set forth in the American Standard Code for Pressure Piping (ASA B31.1—1955), applicable Code Cases and Addenda in effect at the time the valve was ordered, and the requirements set forth in ASA B31 Code Cases N2, N7, N9, and N10 [1] or if ordered after July 26, 1967, meet the requirements set forth in the Power Piping Section of the USAS Standard Code for Pressure Piping (USAS B31.1.0—1967, applicable Code Cases, and Addenda in effect at the time the valve was ordered, and the requirements set forth in ASA B31 Code Cases N2, N7, N9, and N10.[1] For construction authorizations issued on or after April 1, 1970, pumps and valves which are part of the reactor coolant pressure boundary shall meet the requirements for Class I pumps and valves set forth in the draft ASME Standard Code for Pumps and Valves for Nuclear Power, dated November 1968 (excluding Code Cases), the requirements set forth in Appendix IX—Quality Control and Nondestructive Examination Methods, of the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code, and the requirements set forth in paragraph N-153 in the Summer 1969 Addenda dated June 30, 1969, to the 1968 Edition of Section III of the ASME Boiler and Pressure Vessel Code.[1]

(f) *Inservice inspection requirements.* For construction authorizations issued on or after April 1, 1970, pressure vessels, piping, fittings, pumps, and valves which are part of the reactor coolant pressure boundary shall meet the requirements set forth in the draft ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems, dated October 1968 [1] (excluding Code Cases). The requirements of this paragraph need not be met by pressure-containing components whose rupture would not result in a loss of reactor coolant in excess of the replenishment capability and capacity of the normal makeup systems for the interval of time necessary to permit a reactor shutdown and orderly cooldown.

(g) *Protection systems.* For construction authorizations issued after April 1, 1970, protection systems shall meet the requirements set forth in the 1968 Edition of the Proposed Institute of Electrical and Electronics Engineers Criteria for Nuclear Power Plant Protection Systems (IEEE No. 279), dated August 1968.[2]

(h) *Reactor coolant pressure boundary.* As used in paragraphs (c), (d), (e), and (f) of this section "reactor coolant pressure boundary" means all those pressure-containing components, such as pressure vessels, piping, pumps, and valves, within the following systems or portions of systems of boiling and pressurized water-cooled nuclear power reactors:

(1) The reactor coolant system. For a nuclear power reactor of the direct cycle boiling water type, the reactor coolant system extends to and includes the outermost containment isolation valves capable of external actuation,* in the main steam and feedwater piping, and the reactor coolant system safety and relief valves.

(2) Portions of associated auxiliary systems connected to the reactor coolant system. For piping of these systems which penetrates primary reactor containment, the boundary extends to and includes the first containment isolation valve outside the containment capable of external actuation:* For piping of these

*Effective date of these amendments.

[1] Copies may be obtained from the American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, N.Y. 10017. Copies are available for inspection at the Commission's Public Document Room, 1717 H Street NW., Washington, D.C.

[2] A copy may be obtained from the Institute of Electrical and Electronics Engineers, United Engineering Center, 345 47th Street, New York, N.Y. 10017. A copy is available for inspection at the Commission's Public Document Room, 1717 H Street NW., Washington, D.C.

*Simple check valves are not acceptable for this purpose.

systems which contains two valves, both of which are normally closed during normal reactor operation, the boundary extends to and includes the second of these valves (the second of which must be capable of external actuation*), whether or not the system piping penetrates primary reactor containment.

(3) Portions of the emergency core cooling system connected to the reactor coolant system. For piping of this system which penetrates primary reactor containment, the boundary extends to and includes the first containment isolation valve outside containment capable of external actuation.* For piping of this system which does not penetrate primary reactor containment, the boundary extends to and includes the second of two valves normally closed during normal reactor operation.

(Sec. 161, 68 Stat. 948; 42 U.S.C. 2201)

Dated at Washington, D.C., this 17th day of November, 1969.

For the Atomic Energy Commission.

W. B. McCool,
Secretary.

[F.R. Doc. 69-14004; Filed, Nov. 21, 1969; 9:34 a.m.]

INDUSTRY CODES, CODE CASES, AND ADDENDA APPLICABLE TO PRESSURE VESSELS, PIPING, VALVES, AND PUMPS WITHIN REACTOR COOLANT PRESSURE BOUNDARY

	COMPONENT PURCHASE DATE — For Nuclear Power Units With Construction Permits Issued Prior to April 1, 1970											CONSTRUCTION PERMIT DATE
	1965 Jan. – July	July – 1966 Jan.	1966 Jan. – July	July – 1967 Jan.	1967 Jan. – July	July – 1968 Jan.	1968 Jan. – July	July – 1969 Jan.	1969 Jan. – July	July – 1970 Jan.	1970 Jan. – 1970 April 1.	For Nuclear Power Units With Construction Permit Issued On or After April 1, 1970
SURE LS	ASME Section III 1963 Edition Subsection A Addenda Summer 1964 Applicable Code Cases	ASME Section III 1965 Edition Subsection A Applicable Code Cases	ASME Section III 1965 Edition Subsection A Addenda Summer 1965 Applicable Code Cases	ASME Section III 1965 Edition Subsection A Addenda Summer 1965 Winter 1965 Applicable Code Cases	ASME Section III 1965 Edition Subsection A Addenda Summer 1965 Winter 1965 Summer 1966 Applicable Code Cases	ASME Section III 1965 Edition Subsection A Addenda Summer 1965 Winter 1965 Summer 1966 Winter 1966 Applicable Code Cases	ASME Section III 1965 Edition Subsection A Addenda Summer 1965 Winter 1965 Summer 1966 Winter 1966 Summer 1967 Applicable Code Cases	ASME Section III 1968 Edition Subsection A Applicable Code Cases	ASME Section III 1968 Edition Subsection A Addenda Summer 1968 Applicable Code Cases	ASME Section III 1968 Edition Subsection A Addenda Summer 1968 Winter 1968 Applicable Code Cases	ASME Section III 1968 Edition Subsection A Addenda Summer 1968 Winter 1968 Summer 1969 Applicable Code Cases	ASME Section III 1968 Edition Subsection A Addenda Summer 1968 Winter 1968 Summer 1969 ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems - Oct. 1968 Draft
PIPING AND FITTINGS	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N7, N9, N10	USAS B31.7 - Feb. 1968 Draft - Subsection 1, and Errata June 1968 ASME Boiler and Pressure Vessel Code - Section III - Paragraph N153 in Summer 1969 Addenda ASME Section III - Appendix IX ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems - 10/68 Draft
LVES CLUDES SAFETY AND LIEF VES)	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA 631 Code Cases N2, N7, N9, N10	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	ASA B31.1 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	ASA B31 Code 1955 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	USAS B31.1.0 1967 Edition Applicable Code Cases and Addenda ASA B31 Code Cases N2, N7, N9, N10	ASME Standard Code for Pumps and Valves for Nuclear Power-Section A - Nov. 1968 Draft ASME Boiler and Pressure Vessel Code Section III - Paragraph N153 in Summer 1969 Addenda ASME Section III - Appendix IX ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems - 10/68 Draft
PUMPS	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASA B31 Code Cases N7, N9, N10	ASME Standard Code for Pumps and Valves for Nuclear Power-Section A - Nov. 1968 Draft ASME Boiler and Pressure Vessel Code Section III - Paragraph N153 in Summer 1969 Addenda ASME Section III - Appendix IX ASME Code for Inservice Inspection of Nuclear Reactor Coolant Systems - 10/68 Draft

NOTE: COPIES OF ABOVE-MENTIONED INDUSTRY CODES, CODE CASES, AND ADDENDA MAY BE OBTAINED FROM THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS, UNITED ENGINEERING CENTER, 345 EAST 47TH STREET, NEW YORK, N.Y. 10017. COPIES ARE AVAILABLE FOR INSPECTION AT THE COMMISSION'S PUBLIC DOCUMENT ROOM, 1717 H STREET, N.W., WASHINGTON, D.C.

EXHIBIT K

November 16, 1970

SAFETY EVALUATION

BY THE

DIVISION OF REACTOR LICENSING

U. S. ATOMIC ENERGY COMMISSION

IN THE MATTER OF

CONSOLIDATED EDISON COMPANY OF NEW YORK, INCORPORATED

INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

BUCHANAN, NEW YORK

DOCKET NO. 50-247

TABLE OF CONTENTS

1.0 INTRODUCTION

The Consolidated Edison Company of New York, Inc., (applicant) filed with the Atomic Energy Commission (AEC or Commission) an application dated October 15, 1968, for an operating license for its Indian Point Nuclear Generating Unit No. 2. Indian Point Unit 2 has been under construction since issuance of a provisional construction permit on October 14, 1966.

Indian Point Unit 2 is located on a 227-acre site on the east bank of the Hudson River at Indian Point, Village of Buchanan, in upper Westchester County, New York.

Indian Point Unit 2 is the first of the four-loop, current generation Westinghouse pressurized water reactor designs. It will be owned and operated by the Consolidated Edison Company of New York, Inc. The Westinghouse Electric Company (Westinghouse) is the principal contractor and has turnkey responsibility for the design, construction, testing, and initial startup of the facility. Westinghouse contracted with United Engineers and Constructors as architect engineer. Construction of the plant was performed by United Engineers until December 1969 when this function was assumed by WEDCO, a wholly-owned subsidiary of Westinghouse.

The operating license application is for a power level of 2758 megawatts thermal (MWt), the same as was requested in the construction permit application. Our evaluation of the engineered safety features

(with the exception of the emergency core cooling system) and our accident analyses, have been performed for a maximum power of 3216 MWt.

Our evaluation of the thermal, hydraulic, and nuclear characteristics of the reactor core and the performance of the emergency core cooling system was for a power rating of 2758 MWt. Before operation at any power level above 2758 MWt is authorized, the regulatory staff will perform a safety evaluation to assure that the core can be operated safely at the higher power level.

Our technical safety review of the design of this plant has been based on Amendment No. 9 to the application, the Final Facility Description and Safety Analysis Report (FFDSAR), and Amendments Nos. 10-25, inclusive. All of these documents are available for review at the Atomic Energy Commission's Public Document Room at 1717 H Street, Washington, D.C. The technical evaluation of the design of this plant was accomplished by the Division of Reactor Licensing with assistance from the Division of Reactor Standards and various consultants to the AEC.

In the course of our review of the application, many meetings were held with representatives of the applicant to discuss the plant design and proposed operation. As a consequence of our review, additional information was requested, which the applicant provided by amendments to the application. A chronology of the principal actions relating

to the processing of the application is attached as Appendix A to this safety evaluation. In addition to our review the Advisory Committee on Reactor Safeguards (ACRS) independently reviewed the application and met with both the AEC staff and the applicant on several occassions to discuss the plant. The ACRS report on Indian Point Unit 2, dated September 23, 1970, is attached to this Safety Evaluation as Appendix B. Appendices C through G include reports from our consultants on meteorology, hydrology, seismic and structural design, and radiological monitoring. Appendix H contains the staffs evaluation of the applicant's financial qualifications.

Based upon our evaluation of the plant as summarized in subsequent sections of this report, we have concluded that Indian Point Unit 2 can be operated at thermal power levels of up to 2758 MWt without endangering the health and safety of the public. Subsequent to the issuance of an operating license the unit will be required to operate in accordance with the terms of the operating license and the Commission's regulations under the surveillance of the Commission's regulatory staff.

2.0 FACILITY DESCRIPTION

Indian Point Unit 2 is one of three reactors currently planned for the Indian Point site. Indian Point Unit 2 is adjacent to Indian Point Unit 1, a 615 MWt pressurized water reactor plant that has been in operation since August 1962. Indian Point Unit 3, a plant similar to Indian Point Unit 2, received a provisional construction permit in August 1969, and is presently under construction at the Indian Point site. Each unit has its own auxiliary systems and safety features. The three units, however, will share a common inlet water canal and a common discharge canal. In addition, the controls for Indian Point Unit 2 and Indian Point Unit 1 are located in separate portions of a common control room.

The Indian Point Unit 2 pressurized water reactor is fueled with slightly enriched uranium dioxide in the form of ceramic pellets contained in zircalloy fuel tubes. Water serves as both the moderator and the coolant. Heat is removed from the reactor core by four separate coolant loops, each provided with a separate pump and steam generator. The heated water flows through the steam generators where heat is transferred to the secondary (steam) system. The water then flows back to the pumps to repeat the cycle. The system pressure is controlled by the use of a pressurizer in which steam and water are maintained in thermal equilibrium.

The secondary steam produced in the steam generators is used to drive the turbine generator. The heat of condensing steam is rejected to the circulating water system and discharged to the Hudson River. The condensate is then recharged to the steam generators to repeat the secondary cycle.

The primary coolant system includes the reactor, steam generators, primary coolant pumps, primary coolant piping, and the pressurizer. This system is housed inside the containment building which is a steel-lined, leak-tight reinforced concrete structure. The containment provides a barrier to the release to the environment of radioactive fission products that might be released inside the containment in the event of an accident. Auxiliary systems, including the chemical and volume control systems, the waste handling system, and additional auxiliary cooling systems, are housed separately, principally in the adjacent primary auxiliary building. The primary auxiliary building also houses components of the engineered safety features. A separate fuel handling building is provided for storage of spent fuel. A separate turbine building houses the turbine generator.

Control of the reactor is achieved by reactivity control using top entry control elements that are moved vertically within the core by individual control drives. Boric acid dissolved in the coolant is used as a neutron absorber to provide long-term reactivity control.

To assure reactor operation within established limits, a reactor protection system is provided that automatically initiates appropriate actions whenever plant conditions monitored by the system approach preestablished limits. The reactor protection system acts to shut down the reactor, close isolation valves, and initiate operation of the engineered safety features should any or all of these actions be required.

The engineered safety features include an emergency core cooling system that will cool the reactor core in the event of an accident that results in loss of the normal coolant, containment cooling and iodine removal systems that provide for removal of heat and radioactive iodine from the containment atmosphere should such action be required, and a hydrogen control system that will limit the accumulation of hydrogen within the containment in the event of a loss-of-coolant accident. A containment penetration pressurization system and seal water injection system are provided to assist in isolating the containment in the event of an accident and prevent the escape of fission products to the environment outside the plant.

3.0 SITE AND ENVIRONMENT

3.1 Population and Land Use

The Indian Point site consists of 227 acres in the town of Buchanan in upper Westchester County, New York, approximately 24 miles north of the New York City boundary line. The estimated population distribution in the vicinity of the site is presented in table 2.1.

TABLE 2.1

CUMULATIVE POPULATION

Distance (miles)	1960 (U.S. Census)	1980 (Projected)
0-1	1,080	2,100
0-2	10,810	20,900
0-3	29,630	59,520
0-4	38,730	78,800
0-5	53,040	108,060
0-10	155,510	312,640

The minimum radius of the exclusion area* for Indian Point Unit 2 is 520 meters. The applicant has chosen 1100 meters as the outer

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*Exclusion area is defined in the Commission's Site Criteria, 10 CFR Part 100, as that area surrounding the reactor in which the reactor licensee has the authority to determine all activities including removal of personnel and property from the area.

boundary of the low population zone** because of the limited population within this distance from the plant.

The Commission's site criteria guidelines state that the population center distance*** should be at least 1-1/3 times the distance from the reactor to the outer boundary of the low population zone (LPZ), but also state that in applying this guide due consideration should be given to the population distribution within the population center. The nearest corporate boundary of Peekskill (population 19,000) is approximately 800 meters (0.5 miles) from Indian Point Unit 2. Because of the limited population within the low population zone (66) including that portion of Peekskill within the zone, and because Peekskill is of a generally industrial nature in the vicinity of the site and the resident population within and out to 1-1/3 times the low population zone distance is low, we concluded at the time of our construction permit review that the distance selected by the applicant for the exclusion area radius, the LPZ outer boundary, and the population center distance meet the intent of the 10 CFR Part 100 guidelines and are acceptable. On the basis of our evaluation of the potential radiological consequences of postulated design basis accidents,

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**Low population zone is defined in the Commission's Site Criteria, 10 CFR Part 100, as the area immediately surrounding the exclusion area which contains residents, the total number and density of which are such that there is a reasonable probability that appropriate protective measures could be taken in their behalf in the event of a serious accident.

***Population center distance is defined in the Commissions Site Criteria, 10 CFR Part 100, as the distance from the reactor to the nearest boundary of a densely populated center containing more than about 25,000 residents.

we conclude that the calculated doses presented in Section 11.0 of this evaluation are well within the guidelines of 10 CFR Part 100 for these distances.

3.2 Meteorology

The meteorology of the Indian Point site is affected by its position in a deep river valley. Consequently, the wind direction generally follows a pronounced diurnal cycle with unstable flow in the up-river direction during the daytime and stable flow in the down-river direction at night.

The applicant has presented the results of meteorological measurements taken at the site over a period of two years including windspeed, wind direction, and temperature lapse rate data for various heights. We have reviewed the data presented and conclude that they provide an adequate basis for selecting the meteorological parameters used in determining the routine effluent release limits and in evaluating the consequences of postulated accidents. The comments of our meteorological consultants, the Environmental Science Service Administration (ESSA) support this conclusion and are attached as Appendix C.

3.3 Geology and Seismology

During our review of this site prior to issuance of the construction permit for Indian Point Unit 2, we and our consultant, the U. S. Geological Survey, concluded that the geology of the site provides an adequate founding medium for the plant buildings and

structures. No new developments have occurred during the construction permit review of Indian Point Unit 3 or otherwise since our construction permit review for Indian Point Unit 2 to change our previous conclusion on the acceptability of the geological and seismological features of the Indian Point site.

Maximum ground accelerations of 0.10g and 0.15g were used for the Operating Basis Earthquake* and the Design Basis Earthquake**, respectively. These values were selected at the time of the construction permit review. At that time we and our consultant, the U. S. Coast and Geodetic Survey, concluded that they were acceptable for the site.

A strong motion seismograph has been installed on a concrete slab directly on bedrock in the yard area of the plant to record data related to ground motion in the event of a seismic disturbance at or near the site. These data would be employed in an evaluation of the effects of the seismic disturbance to assure the capability for continued safe operation of the plant.

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*"Operating Basis Earthquake" for a reactor site is that earthquake which produces vibratory ground motion for which those structures, systems and components, necessary for continued operation without undue risk to the health and safety of the public are designed to remain functional.

**"Design Basis Earthquake" for a reactor site is that earthquake which produces vibratory ground motion for which those structures, systems, and components, necessary to shut down the reactor and maintain the unit in a safe shutdown condition without undue risk to the health and safety of the public are designed to remain functional.

3.4 Hydrology

The applicant has reevaluated the potential flooding that could occur at the site. The following hypothetical flood conditions were analyzed: (1) the probable maximum flood peak discharge of 1,100,000 cubic feet per second resulting from the probable maximum precipitation occurring over the total basin, a 12,650 square mile area above the plant site; (2) the flooding caused by failure of the Ashoken Dam concurrent with a major river basin flood (standard project flood) with a peak discharge of 705,000 cubic feet per second and a hurricane storm surge (standard project hurricane), and (3) the probable maximum hurricane concurrent with the high spring tide in the Hudson River. These three hypothetical floods are the most severe of several investigated, and each of the three results in a maximum water surface elevation of about 15 feet above mean sea level. We have reviewed the method of calculation and conditions assumed and find that they are conservative and acceptable. Both the U. S. Geological Survey and the Coastal Engineering Research Center provided consulting services with respect to our flooding evaluation. Their reports are attached as Appendix D and Appendix E, respectively.

3.5 Environmental Monitoring

The radioactivity levels in the vicinity of the Indian Point site have been measured by the applicant since 1958 to ascertain the

impact of operation of Indian Point Unit 1 on the background levels of radioactivity. The environs of the Indian Point site have been studied intensively for many years by the Institute of Environmental Medicine at New York University Medical Center. These studies concerned both the exposure to man and to the flora and fauna indigenous to the Hudson River. All the results compiled to date indicate that radioactive effluents from Indian Point Unit 1 operation have produced barely quantifiable radiation exposure to the public and have had no detectable effect on the ecology of the area.

The operational environmental radiation monitoring program for Indian Point Unit 2 will be a continuation of the present program. The program includes direct measurements of gamma radiation and analyses to monitor fallout, air particulates, airborne iodines, water from various surface drinking water supplies, Hudson River water, water from lakes near the site, well water, lake aquatic vegetation, Hudson River vegetation, river bottom sediments, river aquatic biota, terrestrial vegetation, and soil. The report of the U. S. Department of the Interior is attached as Appendix G. This report incorporates the comments of the Federal Water Quality Administration, the Fish and Wildlife Service, and the Bureau of Outdoor Recreation. The report comments favorably on current activities being performed by or for the applicant in connection with determining the effects

of both radiological and thermal discharges at the plant site. Recommendations for continued effort in the area of environmental monitoring and ecological studies are included in the report. This report has been forwarded to the applicant.

We conclude that the applicant's program will be adequate for monitoring the radiological effects of Indian Point Unit 2 operations on the environment and for assessing the effects of releases of radioactivity to the environment from operation of the plant on the health and safety of the public.

4.0 REACTOR DESIGN

4.1 General

The nuclear reactor for Indian Point Unit 2 was designed and manufactured by Westinghouse. The principal design features, materials of construction, and arrangement of various components of the Indian Point Unit 2 core are the same as those for the Rochester Gas and Electric Company's R. E. Ginna facility (Docket No. 50-244), which has been licensed for operation by the Commission and which has completed almost a full year of power operation. Further, the zircalloy clad fuel, burnable poison in the initial core loading, a chemical neutron absorber, and part-length control rods to shape axial power distribution are used in substantially the same manner in both the Ginna and the Indian Point Unit 2 reactors. On the basis of our previous review of all of these features for the Ginna reactor, we conclude that these same features are acceptable for Indian Point Unit 2.

4.2 Nuclear Design

The Indian Point Unit 2 reactor core differs principally from the Ginna and Connecticut Yankee (Docket No. 50-213) reactor cores in that the Indian Point Unit 2 reactor core is somewhat larger. The Indian Point Unit 2 core is about 23% greater in cross sectional area and 20% longer than the Connecticut Yankee core and about 89% greater in cross sectional area and the same length as the Ginna core. Because this larger core could be subject to power

oscillations or power tilts, we reviewed the nuclear design and power distribution detection and control systems for the Indian Point Unit 2 reactor core in detail.

During plant operation, changes in the core power level or the control rod configuration can cause time-dependent variations in the local power distribution as a result of variations in the concentration of fission products and their radioactive decay products. The most significant fission product-decay product chain with regard to core behavior is the decay of iodine-135 to xenon-135 since the latter is a strong absorber of thermal neutrons. The local oscillations in the neutron flux and in the power level can occur even though the average power level of the core is maintained constant, and the magnitude of the oscillations may decrease, remain constant, or increase with time.

The spatial stability of the xenon distribution and resultant core power peaking abnormalities for the Indian Point Unit 2 core have been investigated by Westinghouse with the conclusion that the core is stable against various types of xenon induced spatial oscillations in the X,Y horizontal plane. This conclusion is supported by analysis and by experiments performed in the Connecticut Yankee reactor. An initial test program for Indian Point Unit 2 will be performed to verify this stability. If this initial test program does not demonstrate stability, the applicant has agreed to operate with partially inserted control rods, or to add fixed or burnable poison shims sufficient to assure stability

through reduction of the moderator temperature coefficient, or to operate at reduced power levels. Because of the test program that will be performed and the operating limitations that will be imposed if required, we conclude that the reactor will be stable with respect to potential power oscillations in the X,Y horizontal plane.

The analysis made by Westinghouse indicates that the reactor may be subject to divergent xenon oscillations in the axial direction, resulting in an axial power distribution imbalance or tilt. In view of this, it is assumed that the axial power tilts can occur, and provision is made to detect and control differences in the fraction of the total power generated in the upper and lower halves of the core. Data correlations have been made at the Connecticut Yankee reactor and at the Ginna reactor to relate the readings obtained from the split out-of-core detectors to axial power tilts. Additional correlations will be established during the Indian Point Unit 2 startup tests. Part-length control rods are provided to prevent unacceptable axial power tilts and to control potentially divergent axial xenon spatial oscillations. Analytical studies and experience with the Ginna reactor, provide assurance that any axial oscillations can be controlled such that the power distribution will be maintained within design limits. In addition, automatic protective action is provided to avoid exceeding design power peaking factors at full power in the event of control system malfunctions. To accomplish this, the overtemperature ΔT and overpower ΔT trip set points are automatically reduced in proportion to the axial

power tilt as measured by the split out-of-core neutron detectors. We conclude that the system of detection instrumentation, control with part length rods, and automatic protection for potential axial power tilts is acceptable.

Even in the absence of xenon induced instability, power tilts or imbalances can occur in the horizontal or axial planes as a result of control rod misalignment. Analyses for Indian Point Unit 2 and experiments in the Connecticut Yankee reactor have shown that these power tilts can be detected by (1) the split out-of-core neutron detectors, (2) the core exit thermocouples, or (3) the movable in-core neutron detectors. All of these detectors are required to be operable by the Technical Specifications. In addition detection will ordinarily be readily accomplished by the fixed in-core neutron instrumentation.

The power distribution in the Indian Point Unit 2 core is expected to be stable or only slowly varying within known limits and adequate core instrumentation will always be available to detect, monitor, and diagnose any significant power maldistributions.

We conclude that the Indian Point Unit 2 reactor core nuclear design and instrumentation is acceptable.

4.2 Thermal-Hydraulic Design

We have evaluated the adequacy of the core thermal and hydraulic design, both for steady-state plant operation and for anticipated plant transients. The design criteria selected by the applicant to prevent fuel damage are: (1) the departure from nucleate

boiling (DNB) ratio (determined using the Westinghouse W-3 correlation) shall not be less than 1.3 during normal plant operation or as a result of anticipated transients; and (2) no fuel melting shall occur during either normal operation or anticipated transient conditions. The anticipated plant transients that result in the most severe core thermal transients are loss of coolant flow, excessive load increase, and a loss of external electrical load. The applicant's analyses show that the DNB ratio will be greater than 1.3 for each of these plant transients when operating at the license power level of 2758 MWt. The lowest DNB ratio calculated as a result of any of the plant transients, was for the case of simultaneous loss of electrical power to the four reactor coolant pumps. This transient results in a DNB ratio of 1.42. In addition, no fuel melting is predicted to occur for steady-state operation or as a result of anticipated transients.

As stated above the Indian Point Unit 2 reactor core is designed to undergo anticipated plant transients with a minimum DNB ratio greater than 1.3. On this basis, clad temperature should not be significantly affected by a transient and no fuel failure should occur for the range of fuel element burnup planned for the Indian Point Unit 2 core. As part of a continuing experimental effort to

demonstrate satisfactory performance of fuel at high burnup and high power density, Westinghouse is continuing a fuel irradiation program at conditions significantly in excess of current PWR design limits, and will establish power burnup limits for the fuel. These irradiation programs are being conducted at both the Saxton and Zorita reactors. Sustained operation of selected fuel rods at peak design power levels in the Zorita reactor will increase assurance that the fuel has adequate margins to accommodate transient overpower operation.

Based on our evaluation of the results of these analyses, and on our review of the design limits and the operating experience of similar reactors, we conclude that the reactor core thermal and hydraulic design is acceptable for operation at the rated power of 2758 MWt.

5.0 REACTOR COOLANT SYSTEM

5.1 General

The reactor primary coolant system, including all vessels, pumps, and piping is designed for a pressure of 2485 psig and a temperature of 650°F. The system has been designed to withstand, within the stress limits of the codes used in the design, the normal loads of mechanical, hydraulic, and thermal origin, plus those due to anticipated transients and the operating basis earthquake.

5.2 Primary System Components

The reactor internals are designed to withstand the normal design loads of mechanical, hydraulic, and thermal origin, including those resulting from anticipated plant transients and the operating basis earthquake, within the stress limit criteria of Article 4 of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III. Although the Indian Point Unit 2 reactor internals are not designed to withstand simultaneously the loads resulting from loss-of-coolant accident blowdown and seismic events, the applicant has submitted a summary of an analytical study of the behavior of the reactor internals under simultaneous blowdown and seismic loadings (WCAP-7332-L). The results of this study indicate that for the combined blowdown and design basis earthquake loadings the resulting deflections are within the loss-of-function limits except for the control rod immediately adjacent to the coolant line that was assumed to fail. On the

basis that the core reactor internals remain functional and that adequate shut down margin can be achieved by control rod insertion, we conclude that the stress and deflection limits for the combined blowdown and design basis earthquake loadings provide an adequate margin of safety.

The primary system side of the steam generators, the pressurizer, and the main coolant pump casings, have been designed to the requirements of Section III of the ASME Boiler and Pressure Vessel Code, 1965 Edition - Summer 1969 Addenda, as Class A vessels. For other Class I pumps, valves, and heat exchangers the inspection program required independent review of (1) the physical and chemical test data for pressure boundary materials, (2) radiographs of valve bodies, valve bonnets and pump casings, and (3) dye-penetrant examinations of heat exchanger tubes and welds. These requirements resulted in fabrication and inspection programs that contain the essential elements of the recently proposed ASME Codes for Nuclear Pumps and Valves. We find the design codes and inspection requirements acceptable.

We have reviewed the information submitted by the applicant with respect to operating limitations on heatup and cooldown of the primary system imposed by the fracture toughness properties of the materials of the Indian Point Unit 2 reactor vessel. Our evaluation was based on a proposed redraft of section NB-2300 Special Materials Testing (Section III ASME Boiler and Pressure

Vessel Code) dated July 28, 1970, which reflects the material testing requirements in a form consistent with the AEC Fracture Toughness Criteria. As a consequence of our evaluation the applicant has agreed to the heatup and cooldown limitation as presented in Section 3.1-B of the Technical Specifications which represents a modification of his initial submittal. On the basis that these limits reflect a very conservative method of defining pressure vessel fracture toughness, we conclude that they are acceptable.

5.3 Coolant Piping

The reactor coolant piping has been designed in accordance with the requirements of the American National Standards Institute (ANSI) B31.1 Code for Power Piping, 1955 Edition, including the requirements of Nuclear Code Cases N-7 and N-10. All welding procedures and operators were qualified to the requirements of Section IX of the ASME Boiler and Pressure Vessel Code. Additional inspection requirements for the reactor coolant piping during fabrication included ultrasonic and dye-penetrant inspection of all pipe welds. Non-destructive examination of valves included radiographic examination of the valve castings and ultrasonic inspection of all forged components. Dye-penetrant surface examination was also performed. With this program, the inspection of the Indian Point Unit 2 reactor coolant piping substantially

meets the requirements of Class 1 systems under the ANSI B31.7 Code for Nuclear Power Piping adopted in 1969. On this basis we have concluded that the design and inspection program for this system is acceptable.

The original seismic design analysis for the Indian Point Unit 2 reactor coolant system utilized only static methods of analysis. Recently, at our request, the applicant completed a rigorous dynamic analysis of this system utilizing both modal-response spectra and model time-history methods of analyses. As with the reactor internals, the combined loading of a concurrent loss-of-coolant accident blowdown and design basis earthquake was not considered in the design of the Indian Point Unit 2 reactor coolant system. However, the applicant recently completed an analysis of the response of the reactor coolant system to be installed in Indian Point Unit 3 for these combined loads. Since the Indian Point Unit 3 and the Indian Point Unit 2 reactor coolant systems are identical, the applicant has used the results of the analysis for Indian Point Unit 3 in conjunction with the material properties for the Indian Point Unit 2 piping, as determined from tests, to determine that the combined seismic and accident loads can be tolerated by the Indian Point Unit 2 reactor coolant system within acceptable stress limits.

Based on our review of the design limits and analytical procedures employed, we find that the design of the Indian Point Unit 2 reactor coolant system is acceptable.

5.4 Other Class I* (Seismic) Piping

At our request the applicant performed additional seismic analysis on other Class I piping. The adequacy of the seismic design of the feedwater lines, pressurizer surge line, and a typical steam line has been confirmed by a dynamic analysis utilizing the modal-response-spectra method. The adequacy of the seismic design of other Class I (Seismic) piping in the plant was determined by performing a dynamic analysis on selected "worst case" systems. Several systems that are the most vulnerable to dynamic excitation because of system flexibility or location in the supporting structure were analyzed and the resulting stresses compared with the stresses determined by the original static analyses. The applicant has concluded that the conservatism of the original static analysis provided adequate margins to accommodate the previously undetermined dynamic effects.

Based on our review of the original static methods employed and the confirmatory evidence obtained from the recent dynamic analyses of the most vulnerable systems, we have concluded that the design of the Class I (Seismic) piping systems in Indian Point Unit 2 is acceptable.

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*See Section 6.1 for definition of Class I structures, systems, and components.

5.5 Inservice Inspection

An inservice inspection program for the reactor coolant system is included in the Technical Specifications. This program follows Section XI of the ASME Code, Rules for Inservice Inspection of the Reactor Coolant System, as closely as practical. The design of the primary system including the capability to remove insulation at selected areas provides an acceptable degree of access for inspection purposes. The applicant also intends to conduct periodic inservice inspections of the primary pump motor flywheels.

The applicant will review the inservice inspection program with us after five years of reactor operation. It may then be modified based on experience gained during these five years. At that time, we will also require the applicant to perform such inspections of components outside the reactor coolant pressure boundary as deemed necessary to provide continuing assurance of structural integrity.

5.6 Missile Protection

We have reviewed the applicant's primary system layout within the containment in terms of the protection afforded the containment liner and Class I (seismic) systems inside the containment from missiles that might be generated as a result of a primary system failure. We have concluded that adequate protection from potential missiles is provided by the system arrangement and surrounding thick circumferential concrete walls and the concrete floors.

The primary pump motor flywheels installed in Indian Point Unit 2 are the same as those in use in other plants. The flywheels are the standard Westinghouse design, fabricated of A 533B steel. On the basis of the use of high grade material, extensive quality control measures, special manufacturing procedures and preservice and inservice surveillance requirements, we have concluded that assurance has been provided that the integrity of the flywheels will be maintained.

5.7 Leak Detection

The reactor coolant pressure boundary leak detection systems for this plant are similar to those we have reviewed and found acceptable for other plants using a Westinghouse nuclear steam supply system. The systems are based upon air particulate monitoring, radiogas monitoring, humidity detection, and containment sump level monitoring. These systems provide an array of instrumentation that is sensitive, redundant, and diverse and that has adequate alarm features. The sensitivity of these systems is consistent with their primary purpose of detecting any leak in the primary system pressure boundary which could be indicative of incipient failure. The Technical Specifications require that two reactor coolant leak detection systems of different principles shall be in operation when the reactor is operated at power. We conclude that the leak detection systems for Indian Point Unit 2 are acceptable.

5.8 Fuel Failure Detection

The fuel element failure detection system will measure delayed neutron activity in one hot leg of the reactor coolant system. The monitor is connected in series with a delay coil to allow a decay time for N^{16} gamma activity (half life of 7.1 seconds) of about 60 seconds before the coolant reaches the detector. This delay reduces gamma ray background and facilitates detector sensitivity. An alarm signal is provided for the channel. We conclude that this system which is inherently faster in response than previous systems reviewed for other reactors is acceptable.

5.9 Vibration Monitoring and Loose Parts Detection

The major core and core support components have been analyzed to provide assurance that they are not vulnerable to vibratory excitation. Vibration analyses for the core support barrel considered inlet flow impingement and turbulent flow. Natural frequency calculations were made to assure that there would be no deleterious response to known excitations such as pump blade passing and driven frequencies. Fuel bundle response to anticipated driving forces has been calculated and determined by tests in the Westinghouse Reactor Evaluation Center.

The vibration monitoring system to be used for the preoperational test program on Indian Point Unit 2 will consist of mechanical gauges to measure gross relative motion between the thermal shield and core barrel, strain gauges on selected guide tubes, and

accelerometers on the upper core plate. We have concluded that the vibration design analyses and the preoperational test program are acceptable.

In the course of our review of the Indian Point Unit 2 application, it has been noted that techniques for the analysis of neutron noise spectra and accelerometer measurements on the lower heads of primary system vessels might be developed to provide a useful method for inservice monitoring of reactor coolant systems to detect changes in the vibration of reactor components or the presence of loose parts. The applicant has stated that neutron noise measurements will be made periodically and analyzed to provide developmental information concerning the possible usefullness of this technique in ascertaining changes in core vibration or other displacements. On a similar basis, accelerometers will be installed on the pressure vessel and steam generators to ascertain the practicality of their use to detect the presence of loose parts.

5.10 Conclusion

Based on our review of (1) the codes and standards used for design, (2) the fabrication and inspection procedures, (3) the inservice inspection program, (4) the provisions for missile protection and leak detection, (5) the provision for fuel failure detection, and (6) the provisions for preoperational vibration

testing and the developmental effort for inservice monitoring to detect vibrations and loose parts, we have concluded that the design and inspection procedures for the reactor coolant system for the Indian Point Unit 2 are acceptable.

6.0 CONTAINMENT AND CLASS I (SEISMIC) STRUCTURES

6.1 General Structural Design

The applicant has categorized as Class I (seismic) those structures (e.g., containment structure and primary auxiliary building), and those systems and components (e.g., reactor vessel and internals, emergency core cooling system), whose failure could cause a significant release of radioactivity or that are vital to the safe shutdown of the facility and the removal of decay heat. We have reviewed the applicant's classification of structures, systems, and components and conclude that they have been classified appropriately.

The Class I (seismic) structures at Indian Point Unit 2 are the containment structure, the primary auxiliary building, the control room building, the fuel storage pool, the diesel generator building, and the intake structure and service water screenwell. The major portion of the primary auxiliary building, the fuel storage pool, and the intake structure are of reinforced concrete construction. The control room building, the diesel generator building, the fuel storage building and the non-Class I portions of the primary auxiliary building are constructed of steel framing with composite metal panel siding.

The environmental conditions that were considered in the structural design include the operating basis earthquake (OBE), the design basis earthquake (DBE), the flooding and wind due to

the probable maximum hurricane, and the flooding due to the probable maximum flood. We have concluded that these conditions were used for the design in an acceptable manner.

6.2 Structural Design and Analysis

The Indian Point Unit 2 primary containment has a free volume of 2.6×10^6 cubic feet and a design pressure of 47 psig. The containment structure is a right cylinder (thickness 4.5 ft) with hemispherical dome (thickness 3.5 ft) mounted on a flat (thickness 9 ft) base mat. The reinforced concrete is lined with 1/4 inch minimum thickness welded ASTM A442 grade 60 firebox quality carbon steel plate. The reinforcing bars conform to ASTM A432 specifications. The reinforcing in the cylinder wall is placed in horizontal and vertical directions with added diagonal tangential reinforcing for earthquake resistance. The reinforcing bars conform to ASTM A432 specifications. Cadweld splices are used in 14S and 18S bars.

We have evaluated the pressure transients that might occur in the containment in the event of a loss-of-coolant accident assuming various sizes of primary coolant system breaks. For the range of postulated break sizes up to and including the double-ended severance of the largest reactor coolant pipe, the largest calculated peak containment pressure is 40 psig. The design pressure of the containment exceeds the calculated peak pressure by more than 10% and is acceptable.

The containment is designed to remain within the elastic range for the 0.10g OBE concurrent with the accident and other applicable loads. It is also designed to withstand the 0.15g DBE concurrent with the accident without loss of function.

We and our seismic design consultant, Nathan M. Newmark, are in agreement with the loading combinations and allowable stresses used by the applicant. Stress and strain limits conform to the requirements of ACI 318-63, Part IV-B. The ACI load factors have been replaced by factors suitable for concrete containment structures.

Based on our review of the design of the containment structure and its capability to withstand the predicted pressures from potential accidents, we conclude that the structural design aspects of the containment are acceptable.

In evaluating the capability of the Class I (seismic) structures, systems, and components, to withstand the dynamic loads due to seismic events, our seismic design consultant, Nathan M. Newmark Consultant Engineering Services, considered the geology and nature of the bedrock, design loads and load combinations, the seismic design parameters, and methods of analysis. On the basis of our review and that of our seismic design consultant, we conclude that the Class I (seismic) structures, systems, and components of Indian Point Unit 2 are designed to accommodate all applicable loads and are acceptable. The report of our seismic design consultant is attached as Appendix G.

During our review we noted a limited number of cases where failure of non-Class I (seismic) structures could potentially endanger Class I (seismic) structures and equipment. These included the Indian Point Unit 1 superheater stack and superheater building, the turbine building, and the fuel storage building. In response to our concern, the applicant performed analyses of these structures using a multi-degree of freedom modal dynamic analysis method, to determine the modifications needed to assure that gross structural collapse of these structures would not occur in the event of a DBE. As a result of these analyses, additional seismic reinforcement is being provided for both the superheater building and the turbine building and the Indian Point Unit 1 superheater stack is to be reduced in height by 80 feet. The truncation of the stack is to be accomplished at a convenient time in the next three years and prior to operation of Indian Point Unit 3. We and our seismic design consultant have reviewed the material submitted by the applicant and conclude that the dynamic analyses performed, and the design modifications proposed, are acceptable.

We have reviewed the as-built wind resistance of Class I structures at the Indian Point Unit 2 facility. Analysis indicates that both the containment and reinforced concrete portions of the primary auxiliary building and intake structure can sustain winds in the range of 300 miles per hour. The control building and diesel generator building which are constructed of structural steel with composite metal panel siding, are estimated by the applicant to be capable of sustaining wind loads of up to 160 miles per hour.

Some natural protection from high winds is afforded the control room building and diesel generator building since they are protected by the turbine building to the west, the Indian Point Unit 1 turbine building. superheater building, and containment to the south, the rising hillside to the east, and the containment and rising hillside to the north.

The wind resistance of the Indian Point Unit 1 superheater stack was also considered with respect to preserving the integrity of Indian Point Unit 2. A reduction in stack height of 80 feet coupled with the additional seismic reinforcement of the superheater building (see discussion above) will enable the stack to resist winds with speeds greater than 300 miles per hour.

On the basis of the very low probability for wind speeds greater than 100 miles per hour at the Indian Point site and on the basis of the wind resistance of the Class I (seismic) structures as discussed above, we conclude that Indian Point Unit 2 is adequately protected against high winds.

6.3 Testing and Surveillance

Strength and leakage tests of the containment building will be performed after construction is completed. A 115% overpressure strength test at 54 psig will be conducted and leakage tests will be made at pressures up to 47 psig. As noted in Section 7.3 of this evaluation, pressurized test channels are provided at all liner seams for long-term surveillance. No permanent instrumentation

is being installed on the containment for strength testing, although examinations will be made for cracking and distortion during the pressure test. Periodic leakage rate tests will be performed on the containment and its penetrations.

We have concluded that the provisions for testing and surveillance of the containment are acceptable. Test and surveillance requirements are included in the Technical Specifications.

6.4 Missile Protection

The possibility exists that missiles might be generated in the unlikely event of a failure of the turbine generator. Although the design criteria for Indian Point Unit 2 did not include consideration of protection against missiles resulting from turbine failures, at our request the applicant has assessed the protection available against missiles that might result from a turbine failure at the maximum overspeed condition (133% of rated normal speed). Specific provisions have been added to limit the off-site consequences that could result from a missile failure, and to provide for safe shut down of the unit. These include an alternative cooling water supply for the charging pumps and added missile protection for a potentially vulnerable portion of the auxiliary steam generator feedwater lines. In addition, a second completely independent turbine speed control system has been provided to reduce the probability of a runaway speed condition that might result in a turbine failure. This

system is designed to the requirements of the Institute of Electrical and Electronic Engineers (IEEE) Criteria No. 279 for protection systems. The Technical Specifications require periodic testing of the overspeed devices to assure operability. We conclude that the applicant has made appropriate provisions to reduce the probability of a destructive turbine missile from being generated and affecting Class I (seismic) items.

The Indian Point Unit 2 reactor vessel cavity is designed to protect the containment against missiles that might be produced by postulated failure of the reactor vessel. Failure of the reactor vessel would result in fluid jet-reaction forces in the cavity wall adjacent to the vessel split or crack as well as stress in the cavity wall from a rise in cavity pressure, both of which would result from coolant blowdown. Also reaction forces in the cavity wall and floor might be produced by the impact of missiles generated by pressure vessel failure. By the use of extensive steel reinforcing, the concrete cavity has been designed to resist both fluid jet and missile impact forces that could result from pressure vessel failure by either longitudinal splitting or various modes of circumferential cracking. The cavity is also designed to sustain a fluid pressure rise to 1000 pounds per square

inch. We have reviewed the applicant's analysis and conclude that the cavity as designed provides adequate protection for the containment liner against missiles that might result from a postulated pressure vessel failure.

7.0 ENGINEERED SAFETY FEATURES

7.1 Emergency Core Cooling System

The principal equipment of the emergency core cooling system consists of (1) three 50% capacity high pressure safety injection pumps, (2) two 100% capacity residual heat removal pumps for low pressure injection and external recirculation, (3) two 100% capacity recirculation pumps for recirculation internal to the containment, (4) one 100% capacity boron injection tank, and (5) four 33-1/3% capacity accumulators. This system provides redundant capability to inject borated cooling water rapidly into the core in the event of a loss-of-coolant accident and to maintain coolant above the level of the core for an indefinite period following the accident.

The applicant's evaluation of the performance of these systems is based on detailed analyses of (1) the hydraulic behavior of the primary coolant system during and subsequent to a loss-of-coolant accident, and (2) the thermal response of the core during the same period. The analytical methods used to predict the hydraulic behavior of the primary coolant system during a loss-of-coolant accident have been improved significantly during the construction period for Indian Point Unit 2. The original analysis presented in Volume 4 of the FFDSAR was performed with the FLASH-1 hydraulics computer program. This program is limited to a three-node

representation of the coolant system. Subsequent to the analysis performed with FLASH-1, Westinghouse developed a new multi-node hydraulics program called SATAN. Using SATAN the coolant system can be represented with as many as 96 nodes. The SATAN calculations provide considerable detail in the system analysis and increased insight into system performance.

At our request, the applicant reevaluated the performance of the emergency core cooling system during a loss-of-coolant accident using the SATAN multi-node hydraulics code. The applicant's analysis is based on the license application power rating of 2758 MWt. For the case of an accident initiated by a double-ended break in the cold leg primary coolant piping, a maximum fuel element clad temperature of 2015°F was predicted. The applicant's investigation of the emergency core cooling system performance for a range of break sizes and locations indicates that the resultant peak temperatures for any other break will be less than those predicted for the double-ended cold leg break. On the basis of our review of the analytical techniques used in this analysis and our experience with similar analytical techniques, we conclude that there is reasonable assurance that the results obtained with these techniques provide a conservative estimate of the performance of the system in the event of a loss-of-coolant accident at Indian Point Unit 2.

We conclude that the emergency core cooling system will (1) limit the peak clad temperature to well below the clad melting temperature, (2) limit the fuel clad water reaction to less than 1% of the total clad mass, (3) terminate the clad temperature transient before the geometry necessary for cooling is lost and before the clad is so embrittled as to fail upon quenching and (4) reduce the core temperature and then maintain core and coolant temperature levels in a subcooled condition until accident recovery operations can be accomplished.

In summary, we conclude that the emergency core cooling system is acceptable and will provide adequate protection for any loss-of-coolant accident.

The emergency core cooling system design as presently installed at Indian Point Unit 2 was reviewed by the Division of Reactor Licensing during 1967, subsequent to the issuance of the construction permit on October 14, 1966. This system represented a complete redesign, a considerable increase in flow capability, and enhanced performance when compared to the system reviewed for the construction permit. On the basis that the very significantly improved performance of the redesigned emergency core cooling system provides additional assurance for limiting clad temperatures and maintaining a coolable core we concurred with the applicant's decision to remove the reactor pit crucible from the facility design.

7.2 Containment Spray and Cooling Systems

Two independent heat removal systems are provided to control the containment pressure and temperature following a loss-of-coolant accident. Each system, acting alone at its rated capacity, will prevent over-pressurization of the containment structure. The two systems are the containment spray system and the fan cooling system. The design of each is substantially the same as the design of systems provided at the Ginna plant and other licensed plants.

The containment spray system consists of two 50% capacity spray pumps and is sized to limit the containment post-accident pressure to below design pressure. Sodium hydroxide and boric acid are used as additives to the spray solution to remove radioactive iodine which might be present in the containment after an accident. We have reviewed the use of these chemical spray additives in terms of their iodine removal capabilities, and in addition have evaluated the chemical compatibility of the spray solution with other reactor components. As a result of our review, we conclude that the spray system is adequately sized to cool the containment, that the alkaline spray solution will reduce the iodine concentration in the containment atmosphere, and that corrosion of other materials used in the containment does not introduce a safety problem.

The containment fan cooling system provides complete redundancy to the containment spray system for heat removal from the containment atmosphere during post-accident conditions. Five 20% capacity fan

coolers are provided. Since the fan coolers are located within containment, they must be capable of operating in the post-accident environment. Westinghouse has conducted an environmental test program to demonstrate this capability. Our evaluation of these tests, including the heat removal capability of the heat exchangers, and environmental and radiation testing of the fan cooler motors, valve motor operators and electric cabling indicates that these components will function satisfactorily in the accident environment. An iodine-impregnated charcoal filter system has been included with the fan cooler system to remove organic iodine from the post loss-of-coolant containment atmosphere. The charcoal beds are preceded by demisters and high efficiency particulate air (HEPA) filters.

We have evaluated the inorganic and organic iodine removal capability of the charcoal beds on the basis of tests with steam - air mixtures at 100% relative humidity following prolonged flooding of the bed. We conclude that inorganic and organic iodine removal efficiencies of 90% and 10% per pass, respectively, are conservative values that are justified by the available information.

In summary, we have reviewed the containment spray and fan cooling systems in terms of (1) capability to control the containment temperature, (2) capability to remove inorganic and organic iodine,

(3) system and component redundancy, and (4) capability to function in the post-accident containment environment. We conclude that there is reasonable assurance that these systems will operate as proposed subsequent to a loss-of-coolant accident.

7.3 Containment Isolation Systems

In addition to the usual capability of isolating all lines leading to and from the containment, the Indian Point Unit 2 containment is provided with additional systems to minimize the potential leakage of fission products subsequent to an accident. A containment penetration and weld-channel pressurization system provides for continuous pressurization of zones enclosing containment penetrations and the welds in the containment liner. The system continuously maintains an overpressure of clean, dry air that is in excess of the containment design pressure. Pressurized zones include each piping penetration, each electrical penetration, double gasketed spaces on the personnel and equipment hatches, and the channels over weld seams of the containment liner. The air pressure is maintained by the instrument air compressors with backup from the plant air compressors and from a standby source of nitrogen cylinders. Pressure indication and alarm instrumentation is provided locally and in the control room to assure that loss of pressure will be detected and corrected.

In addition, an isolation seal water system has been provided to assure containment isolation by (1) injecting seal water between the seats and stem packing of the globe and double disc isolation valves used on larger lines, and (2) injecting seal water directly into the line between the closed diaphragm valves used in the smaller lines penetrating containment. Seal water injection is provided for all lines connected to the reactor coolant system and for lines that may be exposed to the containment atmosphere subsequent to an accident. Although the use of the seal water system following a loss-of-coolant accident provides an additional means of reducing leakage, we have not considered the effect of this system in determining the offsite radiological consequences.

We have concluded that the capability provided for isolating the containment is acceptable.

7.4 Post-Accident Hydrogen Control System

In the event of a loss-of-coolant accident, radiation from the core and from escaped fission products will dissociate some of the cooling water into gaseous hydrogen and oxygen. Continued evolution of hydrogen would increase the concentration in the containment to a point where ignition could occur and thus provide an additional energy source.

Redundant flame recombiner units are installed within the Indian Point Unit 2 containment. Each unit has the design capability to prevent the ambient containment hydrogen concentration from exceeding two percent by volume. The units are designed to function, following the loss-of-coolant accident in a containment pressure environment of 1 to 5 psig. Each recombiner system consists of (1) a flame recombiner unit located within containment, (2) a control panel located outside of containment, and (3) a hydrogen gas stand located outside of containment. On the basis of (1) our detailed review of the design of the system and its controls, (2) satisfactory performance testing of the device, and (3) satisfactory environmental testing of those portions of the recombiner system installed within the containment, we conclude that there is reasonable assurance that the recombiner system will perform its intended post-accident function.

In addition, the applicant will provide the capability for purging the containment atmosphere through appropriate filters as an alternate backup means of hydrogen control. The containment penetrations to be used for this system are installed. The design and installation of the equipment required will be performed during the first two years of operation at power.

8.0 INSTRUMENTATION, CONTROL, AND POWER SYSTEMS

8.1 Reactor Protection and Control System

The reactor protection system instrumentation for Indian Point Unit 2 is the same as that installed at the Ginna plant. The adequacy of the protection system instrumentation was evaluated by comparison with the Commission's proposed general design criteria published on July 11, 1967, and the proposed IEEE criteria for nuclear power plant protection system (IEEE-279 Code), dated August 28, 1968. The basic design has been reviewed extensively in the past and we conclude that the design for Indian Point 2 is acceptable.

During our review we considered the adequacy of reactor protection for operation with less than four coolant loops in service. When operating with one of the primary loops out of service the reactor is normally automatically limited to 60% of full power. However by manual adjustment of several protection system set points in a manner consistent with the Technical Specifications adequate reactor protection can be provided for operation up to 75% of full power.

We have reviewed the applicant's analysis of the seismic response of the protection system instrumentation and associated electrical equipment and find that adequate testing has been performed on the nuclear instrumentation, switch gear, and process system instrumentation.

In connection with our review of potential common mode failures we have recently considered the need for means of preventing common failure modes from negating scram action and of possible design features to make tolerable the consequences of failure to scram during anticipated transients. The applicant has been responsive to our request for information and has provided the results of analyses which indicate that the consequences of such transients are tolerable for the existing Indian Point Unit 2 design at a power level of 2758 MWt. Although additional study is required of this general question, we conclude that it is acceptable for the Indian Point Unit 2 reactor to operate at a power level of 2758 MWt while final resolution of this matter is made on a reasonable time scale.

8.2 Initiation and Control of Engineered Safety Features

The instrumentation for initiation and control of engineered safety features for the Indian Point Unit 2 is the same as that installed at the Ginna plant. This basic design has been reviewed extensively in the past and we consider it to be acceptable.

We have reviewed the capability for testing engineered safety feature circuits during reactor operation. Resistance tests will be used for routine determinations of the operability of the master and slave relay coils. The circuits upstream of these relays can be partially tested during operation. During plant shutdown, circuits can be tested completely by coincident tripping of instrument channels and a consequent operation of the master and slave relays in the entire downstream initiating system. We have concluded that this

testing capability is acceptable for Indian Point Unit 2.

8.3 Off-Site Power

Two 138 kilovolt (kV) lines connect the Buchanan switchyard to the Millwood switching station, which in turn is connected to the Consolidated Edison grid and the Niagara Mohawk and Connecticut Light and Power systems. Two additional 138 kV lines, using a separate route from the first two lines, connect the switchyard to the Orange and Rockland tie.

The applicant stated that an analysis of the transmission system has indicated that the system is stable for the loss of any generating unit including Indian Point Unit 2.

A single 138 kV line connects the Buchanan switchyard to Indian Point Unit 2. In addition, three 13 kV lines connect the switchyard to Indian Point Unit 1. Three 138/13 kV transformers in the switchyard feed these three 13 kV lines. While the 138 kV system is the normal supply for the auxiliary load associated with plant engineered safety features, one of the three Indian Point Unit 1 13 kV lines is available to provide power via automatic switching to Indian Point Unit 2 through a 13/6.9 kV transformer. By switching circuit breakers in Indian Point Unit 1, the other two 13 kV lines can also be made available to provide power to Indian Point Unit 2. As the 13/6.9 kV supply is not capable of carrying the total plant auxiliary load for Indian Point Unit 2, the main coolant pumps and the circulating water pumps must be tripped off before the supplies are switched.

We conclude that the off-site power supply provides an adequate source of power for the engineered safety features and safe shutdown loads.

8.4 Onsite Power

Onsite power is supplied by three independent diesel generator sets connected in a separate bus configuration such that there is no automatic closure of tie breakers between the three buses to which the generators are connected. The redundant engineered safety feature (ESF) loads are arranged on the three separate buses such that failure of a single bus will not prevent the required ESF performance under accident conditions. The design engineered safety feature and safe shutdown loads per diesel generator are 1813, 2210, and 2353 HP for the first one-half hour following a loss-of-coolant accident. The loads are then changed to 2438, 2235, and 2043 HP for the recirculation phase of the emergency core cooling system operation. On the basis of our evaluation, we have determined that the appropriate diesel generator ratings are 2200 HP continuous, and 2460 HP for 2,000 hours. We note that some of the estimated emergency loads are above the continuous rating of the machines, but below the 2,000 hour ratings. We consider that this margin is acceptable for Indian Point Unit 2.

Each diesel generator is started automatically upon initiation of emergency core cooling system operation or upon under-voltage on its corresponding 480-volt emergency bus. The generators are

housed in a separate Class 1 (seismic) structure. On-site diesel fuel storage capacity provides a minimum of seven days operation at the required safety feature loads. These design and operating features are acceptable for Indian Point Unit 2.

Our review of the ac auxiliary power system has disclosed that there is adequate capacity and an adequate degree of physical and electrical separation of redundant features. The 125 volt dc system consists of two individually housed batteries. The dc system is divided into two buses with a battery and battery charger for each bus. Each of the two station batteries has been sized to carry its expected loads for a period of two hours following a plant trip at a loss of all ac power.

We conclude that the onsite emergency power system is acceptable.

8.5 Cable Installation

We have reviewed the applicant's cable installation relative to the preservation of the independence of redundant channels by means of separation, and relative to the prevention of cable fires through proper cable rating and tray loading. This has been performed by reviewing the cable installation criteria and method of layout design and by field inspection of electrical cable installation during construction.

A single electrical tunnel carries the electrical cables from the electrical penetration area of the containment to the control building. This tunnel carries all of the electrical cables except the power cables for the reactor coolant pumps, the pressurizer

heater cables, and the control rod power cables. The cables in the tunnel are arrayed on either side of a three-foot aisle in trays or ladders. Separation is provided for in the form of distance, metal separators, or transite barriers. The electrical tunnel does not contain any spliced cable connections. Therefore, the probability of a fire is reduced. Further, a fire detection system and an automatically operated water spray system are provided in the tunnel. Tunnel cooling is provided for by redundant cooling fans. On the basis of adequate separation within the tunnel, a minimum number of heat producing cables and features, redundant cooling systems, and fire detection and spray systems we conclude that the single electrical tunnel is acceptable.

Sixty electrical penetrations are provided in a single electrical penetration area to provide for entry of signal, control, and power cables into the containment. The penetrations are located on three-foot centers, both horizontally and vertically, and are of the hermetically sealed type. As a result of our review, fire barriers in the form of transite sheets were added to separate the power cable penetration from the instrument and control cable penetrations. In addition, as a result of our review certain modifications were made to the cabling in the penetration area, including shortening of cable runs and elimination of cable loops. The segregation of power cables and the shortening of the cable runs reduces the probability of failure by fire and on this basis, we consider the single electrical penetration area acceptable for Indian Point Unit 2.

The applicant has performed a design audit to verify the separation of redundant engineered safety feature power and control electrical cabling. A design review of instrument cabling was also performed on a sample basis.

On the basis of our review of cable installation at Indian Point Unit 2, we conclude that the resulting cable layout, as installed, is acceptable.

8.6 Environmental Testing

Westinghouse has conducted an environmental test program for the instrumentation and controls that are located inside containment and that must function in the environment following a loss-of-coolant accident. We have reviewed the results of this testing program and conclude that the essential instrumentation and controls will function properly in the accident environment.

9.0 RADIOACTIVE WASTE CONTROL

Liquid and gaseous waste handling facilities are designed to process waste fluids generated by the plant so that discharge of liquid and gaseous effluents to the environment will be minimized. Liquid waste is processed both by direct removal of radioactive material with ion exchange resins and by evaporative separation. Using these methods the volume of radioactive waste will be greatly concentrated and the purified liquid streams will either be reused or discharged. Small quantities of radioactive liquid waste will be released routinely to the condenser circulating water discharge canal common to all three units where the waste will be diluted and discharged to the Hudson River.

The limits on routine radwaste releases from the three units that are planned for operation at the Indian Point site will require that the combined releases from the three units when added together be within the limits specified in 10 CFR Part 20. This requirement is stated in Section 3.9 of the Technical Specifications for both liquid and gaseous effluents.

The liquid effluent releases from the three nuclear facilities will be discharged from a common discharge canal into the Hudson River. The nearest sources of public drinking water supplies from the Hudson River are located at Chelsea, New York (backup water supply for New York City) and at the Castle Point Veterans Hospital, 22 and 20.5 miles upstream of the Indian Point site, respectively.

During dry periods with low fresh water river flow, tidal action could carry the radioactivity discharge into the river at the Indian Point site upstream to these river water intake points. Conservative analyses made by the applicant indicate that the concentration of radionuclides at these public water intake points would be less than 1% of the concentration of radionuclides being discharged into the river at Indian Point. Since the releases at the site will be less than the limits of 10 CFR Part 20 (and are expected to be less than 10% of the 10 CFR Part 20 limits, based on past experience with Indian Point Unit 1 and other pressurized water reactor plants), the radioactivity levels at these intakes due to the discharges at Indian Point will not be significant.

Gaseous wastes containing some radioactivity are stored in one of four gas decay tanks. One gas tank is utilized for filling, one for holdup for a 45-day decay period, one for discharging to the atmosphere, and one is held in reserve. Disposal of gaseous wastes from Indian Point Unit 2 is by discharge through the plant vent.

The routine gaseous radioactivity releases from the three nuclear facilities will be from three different vents. The combined release of gaseous waste containing radioactivity from these three sources will be limited by the Technical Specifications such that annual average concentrations at the minimum exclusion distance will not exceed the limits of 10 CFR Part 20, Appendix B,

of the Commission's regulations. For gaseous halogens and particulates with half-lives greater than eight days, the applicable limits of the Technical Specifications are less than 1% of the limits given in 10 CFR Part 20. The Technical Specifications also require that the maximum release rate of gaseous waste not exceed the annual average limit.

Based on our review we conclude that the means provided by the applicant for the disposal of radioactive waste are substantially the same as those we have approved for other facilities and are acceptable. We also conclude that acceptable means are provided and will be used to keep the release of radioactivity from the plant within ranges that we consider to be as low as practicable.

10.0 AUXILIARY SYSTEMS

The auxiliary systems necessary to assure safe plant shutdown include (1) the chemical and volume control system, (2) the residual heat removal system, (3) the component cooling system, and (4) the service water system. The systems necessary to assure adequate cooling for spent fuel include (1) the spent fuel pool cooling system, (2) the fuel handling system, and (3) the service water system. The designs for these systems are substantially the same as those we reviewed and found acceptable for the Ginna plant.

10.1 Chemical and Volume Control System

The chemical and volume control system (1) adjusts the concentration of boric acid for reactivity control, (2) maintains the proper reactor coolant inventory and water quality for corrosion control, and (3) provides the required seal water flow to the reactor coolant pumps. The amount of boric acid to be added to the core for reactivity control is determined by the operator. The addition of unborated water as a result of operator error could result in an unintentional dilution during refueling, reactor startup, and power operation. The applicant's analysis indicated that because of the slow rate of dilution there is ample time for the operator to become aware of the dilution and to take corrective action. The applicant is actively participating in the development of a device for continuous monitoring of the reactor coolant boron concentration and will evaluate the feasibility of installing such a monitor when developed.

Our review of the chemical and volume control system emphasized those portions involved in routine and emergency injection of concentrated boric acid. We conclude that the design is acceptable.

10.2 Auxiliary Cooling Systems

Subsystems for auxiliary cooling are the component cooling system, the residual heat removal loop, the spent fuel pool cooling loop, and the service water system. The piping for these three systems is designed to the ANSI B31.1 Code for Pressure Piping.

These systems are equivalent in purpose and design to those of other recently licensed plants. On the basis of our review of this plant and others using the similar systems, we have concluded that these systems are acceptable.

10.3 Spent Fuel Storage

The fuel handling system is designed to transfer spent fuel to the storage pool and to provide storage for new fuel. The spent fuel storage facility is basically the same in capacity and design as those used in previously licensed pressurized water reactor plants. The fuel pool is sized to accommodate spent fuel from 1-1/3 core loadings.

As in other designs, mechanical stops will be incorporated in the crane to restrict motion of the spent fuel cask to its assigned area, adjacent to one side of the fuel storage pool. In addition, the spent fuel racks in the area adjacent to the fuel cask storage

location would be used only in the event that a complete core is unloaded and one-third of a core from a previous unloading is already in storage.

The pool floor is located below grade level and founded on solid rock. Structural damage from a dropped fuel cask would not result in a rapid loss of water from the pool. Makeup water can be supplied from the demineralizer water supply at a flow rate of 150 gpm. Additional water can be provided in an emergency by the use of temporary hookups to other sources.

As a consequence of our evaluation of the potential consequences of a postulated fuel handling accident, the applicant has agreed to provide charcoal filters in the refueling building to reduce the calculated offsite doses that might result in the event of a fuel handling accident in the refueling building. The installation of the filters will be completed during the first year of full power operation.

We conclude that the designs of the spent fuel storage pool and the fuel handling system are acceptable.

11.0 ANALYSES OF RADIOLOGICAL CONSEQUENCES FROM DESIGN BASIS ACCIDENTS

11.1 General

In order to assess the safety margins of the plant design, a number of operating transients were considered by the applicant, including rod withdrawal during startup and at power, moderator dilution, loss of coolant flow, loss of electrical load, and loss of ac power. The reactor control and protection system is designed so that corrective action is taken automatically to cope with any of these transients. Based on our evaluation of the information submitted by the applicant and our evaluations of other PWR designs at the operating license stage, we conclude that the Indian Point Unit No. 2 control and protection system design is such that these transients can be terminated without damage to the core or to the reactor coolant boundary, and with no offsite radiological consequences.

The applicant and we have evaluated the consequences of potential accidents, including a control rod ejection accident, an accident involving rupture of a gas decay tank, a steamline break accident, a steam generator tube rupture accident, a loss-of-coolant accident, and a refueling accident.

The calculated offsite radiological doses that might result from the control rod ejection accident, and the accident involving rupture of a gas decay tank are well within the 10 CFR Part 100 guidelines.

The consequences of the steamline break and the steam generator tube rupture accidents can be controlled by limiting the permissible concentrations of radioactivity in the primary and secondary coolant systems. The Technical Specifications for the Indian Point Unit No. 2 facility limit the primary and secondary coolant activity concentrations such that the potential 2-hour doses at the exclusion radius that we calculate for these accidents do not exceed 1.5 Rem to the thyroid or 0.5 Rem to the whole body.

Our evaluations of the loss-of-coolant accident and the refueling accident are discussed in the following sections.

11.2 Loss-of-Coolant Accident

The design basis loss of coolant accident (LOCA) for the Indian Point Unit No. 2 plant is similar to that evaluated for other PWR plants in that a double-ended break in the largest pipe of the reactor coolant system is assumed.

Although the basis for the design of the emergency core cooling system is to limit fission product release from the fuel, in our conservative calculation of the consequences of the LOCA we have assumed that the accident results in the release of the following percentages of the total core fission product inventory from the core: 100% of the noble gases, 50% of the halogens, and 1% of the solids. In addition, 50% of the halogens that are released from the core is assumed to plate out onto internal surfaces of the containment

building or onto internal components and is not available for leakage. We assume that 10% of the iodine available for leakage from the containment is in the form of organic iodide, and that 5% is in the form of particulate iodine. The reactor is assumed to have been operating at a power of 3217 MWt prior to the accident. The primary containment is assumed to leak at a constant rate of 0.1 percent of the containment volume per day for the first day and 0.05 percent per day thereafter. We evaluated the iodine removal capability of the sodium hydroxide containment spray system and assumed an inorganic iodine removal constant of 4.5 per hour for the spray system. We evaluated the iodine removal capability of the iodine impregnated charcoal filter system and assumed a removal constant of 0.49 per hour for inorganic iodine and a removal constant of 0.048 per hour for organic iodine. Iodine particulates are assumed to be removed by the high efficiency particulate air filters. The inhalation rate of a person offsite is assumed to be 3.5×10^{-4} cubic meters per second.

For the calculation of the two-hour dose at the site boundary we used an atmospheric dispersion factor corresponding to Pasquill Type "F" stability, with a 1 meter per second wind speed and an appropriate building wake effect. We calculated the potential doses at the site boundary for this 2 hour period to be 180 Rem to the thyroid and 4 Rem to the whole body. At the low population zone boundary our calculated potential doses for a 30-day period are 270 Rem to the thyroid and 7 Rem to the whole body.

In evaluating the above doses, no credit was given for the isolation valve seal water injection system, the penetration pressurization system, or the weld channel pressurization system. Operation of these systems, which interpose a high gas pressure or seal water area between the containment and the outside atmosphere at all points where leakage might occur, should significantly reduce the leakage rate from the containment, and, thus reduce the doses following an accident. These systems are well designed and tested, and should be available in the event of an accident (see Section 7.3). We did not consider the effect of these systems in our dose calculations because it is inherently difficult to accurately measure leakage rates of less than 0.1% per day by current testing methods.

The control room for Indian Point Unit No. 2 was not designed to meet the requirements we have imposed in more recent construction permit reviews, that the dose for the course of the accident to occupants of the control room be limited to 5 Rem to the whole body and 30 Rem to the thyroid. In order to provide additional protection to the control room occupants in the event of a loss-of-coolant accident, the applicant has equipped the control room with protective clothing and self-contained air respirators for the operators. In view of these provisions, we have concluded that the control room, as constructed, is acceptable in this regard.

11.3 Fuel Handling Accident

We have evaluated the potential consequences of a fuel handling accident, in which it is postulated that a fuel assembly is dropped in the spent fuel pool or transfer canal. We assumed that: (1) all 204 rods in the dropped bundle are damaged, (2) the accident occurs 90 hours after shutdown of the core from which the dropped bundle has been removed, (3) 20% of the noble gases and 10% of the iodine in the dropped fuel bundle are released to the refueling water and the dropped fuel bundle has been removed from a region of the core which has been generating 1.43 times the average core power, (4) 90% of the released iodine is retained in the refueling water, (5) the fission products released from the pool are discharged to the atmosphere by the building recirculation system through charcoal filters with an iodine removal efficiency of 90%, and (6) the same meteorological conditions exist as were assumed for the loss-of-coolant accident. The resultant calculated doses at the site boundary are 146 Rem to the thyroid and less than 4 Rem to the whole body.

11.4 Conclusions

We have calculated offsite doses for the design basis accidents that have the greatest potential for offsite consequences using assumptions consistent with those we have used in previous safety reviews of PWR plants and have found the resulting calculated doses to be less than the guideline values of 10 CFR Part 100.

12.0 CONDUCT OF OPERATIONS

12.1 Technical Qualifications

The Indian Point Unit 2 facility was designed and is being built by Westinghouse as prime contractor for the applicant. Preoperational testing of equipment and systems at the site and initial plant operation will be performed by Consolidated Edison personnel under the technical direction of Westinghouse. The applicant's experience in the power production field is largely with thermal power plants. However, the applicant has operated Indian Point Unit 1, a 615 megawatt (thermal) pressurized water reactor plant with an oil fired superheater, since August 1962. In addition, the applicant has the Indian Point Unit 3 under construction at the Indian Point site and is actively considering the installation of other nuclear power plants at other sites. Our review of the applicant's organization indicates that the competence of its engineering staff has continually increased and is consistent with the requirements of its expanded nuclear program.

12.2 Operating Organization and Training

The applicant's organization consists of three main groups under the direction of the general superintendent. These groups are the operations group (with a separate superintendent for each unit), the performance group (with the responsibility for station chemistry, licensed personnel training, and surveillance of station performance),

and the health physics group headed by a supervisor engineer for health physics (with the responsibility for station health physics and instrumentation). An assistant superintendent for maintenance, and production engineers (responsible for providing staff support for the operation superintendents) report to the two superintendents for operation. A reactor engineer reports directly to the general superintendent.

The proposed shift complement for the combined operation of Indian Point Unit 1 and Indian Point Unit 2 consists of one general watch foreman licensed as a senior reactor operator (SRO), one watch foreman (SRO) for each unit, one control operator A licensed as a reactor operator (RO) for each unit, one unlicensed control room operator B, shared by both units, one control operator B for Indian Point Unit 1 chemical system building, six operating mechanics (two of whom are assigned to Indian Point Unit 2), one shift chemist, and one shift health physics technician.

The shift composition for Indian Point Unit 2 when Indian Point Unit 1 is shutdown for any reason is the general foreman, one watch foreman, one control operator A and two operating mechanics. In addition, a control room operator B may be available a substantial portion of his time. We conclude that both the dual unit crews and single unit crews as outlined above are acceptable.

Since a large part of the plant staff has had prior nuclear experience, the training program has been fitted to individual needs based on experience, educational background and job responsibilities. The training program includes long- and short-term assignments of key staff personnel to technical institutions and operating reactors, to the Westinghouse offsite operator training school, and to on-site classroom training courses for operators and supervisors conducted by both applicant and Westinghouse personnel. We have reviewed these activities in detail and conclude that the combination of reactor operating experience and formal training obtained by the plant staff has adequately prepared them to perform their operational duties.

As a means for the continuing review and evaluation of plant operational safety, the applicant will expand the responsibilities of the Nuclear Facility Safety Committee currently functioning for Indian Point Unit 1 to include Indian Point Unit 2. The committee, which reports to the Executive Vice President, Central Operations, will have a membership of at least 12 persons, and will have responsibilities to: (1) audit and report upon the adequacy of all procedures used in the operation, maintenance, and environmental monitoring of each nuclear plant; (2) review and report upon the adequacy of all proposed changes in plant facilities and procedures pertaining to operation, maintenance, and environmental monitoring and having safety significance;

(3) review and report upon all proposed changes to the Technical Specifications; (4) conduct unannounced spot inspections of plant monitoring operations; (5) review and report upon any activity, the occurrence or lack of which may affect the safe operation of the nuclear plant; and (6) convene, at the request of the nuclear power generation manager or a nuclear plant general superintendent or chairman or vice chairman of the committee, to review and act upon any matter they may deem necessary.

Westinghouse will participate in the startup and initial operation of the plant and will continue to make available technical support to the Indian Point Unit 2 staff during operation of the facility.

We conclude that the applicant's organization is acceptably staffed and technically qualified to perform its operational duties subject to satisfactory completion of licensing examinations of personnel requiring licenses.

12.3 Emergency Planning

The site emergency plan for the Indian Point site describes the emergency organization and its responsibilities. The scope of the emergency plan includes consideration of local contingencies, site contingencies, general (off-site) contingencies, implementation levels for each contingency, notification channels, the support provided by civil authorities, protective measures for each

contingency, communications facilities, and training drills. The applicant has provided an extensive description of the medical support that will be available although it is not incorporated explicitly in the plan. The planned medical support provides for emergency treatment of plant personnel both at the site and at a designated hospital where facilities equipment and medical personnel to handle radiation contaminated injured personnel will be available.

We conclude that the applicant's emergency plan is acceptable for Indian Point Unit 2.

12.4 Industrial Security

The immediate plant area (restricted area), including Indian Point Unit 1 will be enclosed by a fence. Access to the restricted area for all personnel will be through manned gatehouses or locked gates which are under the direct control of the station security forces. Security guards will make routine patrols of all property within the site boundary and outside the restricted area and are required to make hourly reports to the central control room.

The controlled area of Indian Point Unit 2 will include the containment, the fuel storage building, the primary auxiliary building, and the emergency diesel generator building. Normal access to these areas is through the existing security room for Indian Point Unit 1. All other doors and hatches leading into the controlled area will be locked and will be supervised by means of door switches connected to the open door alarm board in the

security room, and the category alarm board in the Indian Point Unit 1 central control room. The containment personnel hatch doors have remote indicating lights and annunciators that are located in the control room and that indicate the door operational status.

Offsite applicant employees must identify themselves at the main gate prior to admission to the restricted area, receive approval for entry by the general superintendent or his designated representative, and sign in on an admission sheet. If access into the controlled area is approved, they must be accompanied by a qualified guide.

We conclude that the applicant has taken reasonable measures to provide for the security of the facility.

13.0 TECHNICAL SPECIFICATIONS

The Technical Specifications in an operating license define safety limits and limiting safety system settings, limiting conditions for operation, periodic surveillance requirements, certain design features, and administrative controls for the operating plant. These specifications cannot be changed without prior approval of the AEC. The applicant's initial proposed Technical Specifications, presented in Amendment No. 20, have been modified as a result of our review to describe more definitively the allowable conditions for plant operation. The Technical Specifications as approved by the regulatory staff, may be examined in the Commission's Public Document Room.

Based upon our review, we conclude that normal plant operation within the limits of the Technical Specifications will not result in potential offsite exposures in excess of 10 CFR Part 20 limits and that means are provided for keeping the release of radioactivity from the plant within ranges that we consider as low as practicable. Furthermore, the limiting conditions of operation and surveillance requirements will assure that necessary engineered safety features to mitigate the consequences of unlikely accidents will be available.

14.0 REPORT OF ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The ACRS reported on the application for construction of the Indian Point Unit 2 at the proposed site in a letter dated August 16, 1966. The applicant has been responsive to the recommendations made by the ACRS in that letter, and we conclude that the matters raised have been resolved satisfactorily during the design and construction of the Indian Point Unit 2.

The ACRS reported on its review of the application for an operating license for Indian Point Unit 2 in their letter, dated September 23, 1970, attached as Appendix B.

In its letter, the ACRS made several recommendations and noted several items all of which have been considered in the indicated sections of our evaluation. These include: (1) reevaluation of potential flooding at the Indian Point site (Section 3.4), (2) additional seismic reinforcing at the Indian Point Unit No. 1 superheater building and truncation of the superheater stack (Section 6.2), (3) reactor design, power distribution, and control of potential xenon oscillations (Section 4.2), (4) containment design and isolation (Sections 6.2 and 7.3), (5) containment cooling and iodine removal systems (Section 7.2), (6) emergency core cooling system and removal of the reactor pit crucible (Section 7.1), (7) post-accident hydrogen control (Section 7.4),

(8) charcoal filters in the refueling building (Section 10.3), (9) reactor core instrumentation (Section 4.2), (10) reactor protection with only three of four loops in service (Section 8.1), (11) inservice vibration monitoring and loose parts detection (Section 5.9), (12) fuel failure detection (Section 5.9), (13) availability requirements for primary coolant leak detection systems (Section 5.7), (14) pressure vessel fracture toughness (Section 5.2), (15) integrity of high burnup fuel during design transients (Section 4.3), and (16) common mode failure and anticipated transients without reactor scram (Section 8.1).

The ACRS concluded in its letter that if due regard is given to the items recommended above, and subject to satisfactory completion of construction and preoperational testing of Indian Point Unit 2, there is reasonable assurance that this reactor can be operated at power levels up to 2758 MWt without undue risk to the health and safety of the public.

15.0 COMMON DEFENSE AND SECURITY

The application reflects that the activities to be conducted will be within the jurisdiction of the United States and all of the directors and principal officers of the applicant are United States citizens.

The applicant is not owned, dominated or controlled by an alien, a foreign corporation, or a foreign government. The activities to be conducted do not involve any restricted data, but the applicant has agreed to safeguard any such data which might become involved in accordance with the requirements of 10 CFR Part 50. The applicant will rely upon obtaining fuel as it is needed from sources of supply available for civilian purposes, so that no diversion of special nuclear material for military purposes, is involved. For these reasons and in the absence of any information to the contrary, we have found that the activity to be performed will not be inimical to the common defense and security.

16.0 FINANCIAL QUALIFICATIONS

The Commission's regulations that relate to the financial data and information required to establish financial qualifications for an applicant for an operating license are 10 CFR Part 50.33(f) and 10 CFR Part 50 Appendix C. The Consolidated Edison Company's application as amended by Amendment No. 21 thereto, and the accompanying certified annual financial statements provided the financial information required by the Commission's regulations.

These submittals contain the estimated operating cost for each of the first five years of operation plus the estimated cost of permanent shutdown and maintenance of the facility in a safe condition. The estimated operating costs are $10.0 million for 1971 (the first year of operation), $14.8 million for 1972, $12 million for 1973, $10.9 million for 1974 and $10.7 million for 1975 (Amendment No. 21). Such costs include the costs of operating and maintenance and fuel. The applicant's estimate of the cost of permanently shutting down the facility and maintaining it in a safe condition is (1) $265,000 for the first year of shutdown and $50,000 for each year thereafter if the reactor core is removed from the vessel, and (2) $240,000 per year if the core is not removed.

We have examined the certified financial statements of the Consolidated Edison Company to determine whether the Company is financially qualified to meet these estimated costs. The information contained in the 1969 financial report indicates that operating revenues

for 1969 totaled $1,028.3 million; operating expenses (including taxes) was $830.5 million; the interest on the long-term debt was earned 2.3 times; and the net income for the year was $127.2 million, of which $102.1 million was distributed as dividends to the stockholders, and the remainder of $25.1 million was retained for use in the business. As of December 31, 1969, Company's assets totaled $4,069.6 million, most of which was invested in utility plant ($3,793.3 million), and earnings reinvested in the business were $426.1 million. Financial ratios computed from the 1969 statements indicate a sound financial condition, (e.g., long-term debt to total capitalization--0.52, and to net utility plant--0.52; net plant to capitalization--0.994; the operating ratio--0.81; and the rates of return on common--7.7%; on stockholder's investment--6.9%; and on total investment--4.9%). The record of the Company's operations over the past 5 years reflects that operating revenues increased from $840 million in 1965 to $1,028 million in 1969; net income increased from $111.8 million to $127. million; and net investment in utility plant from $3,170 million to $3,793 million. Moody's Investors Service (August 1969 edition) rates the Company's first mortgage bonds as A (high-medium grade). The Company's current Dun and Bradstreet rating (July 1970) is AaAl.

Our evaluation of the financial data submitted by the applicant, summarized above, provides reasonable assurance that the applicant possesses or can obtain the necessary funds to meet the requirements of 10 CFR Part 50.33(f) with respect to the operation of Indian Point Unit 2. A copy of the staff's financial analysis is attached as Appendix H.

17.0 FINANCIAL PROTECTION AND INDEMNITY REQUIREMENTS

Pursuant to the financial protection and indemnification provisions of the Atomic Energy Act of 1954, as amended (Section 170 and related sections), the Commission has issued regulations in 10 CFR Part 140. These regulations set forth the Commission's requirements with regard to proof of financial protection by, and indemnification of, licensees for facilities such as power reactors under 10 CFR Part 50.

17.1 Preoperational Storage of Nuclear Fuel

The Commission's regulations in Part 140 require that each holder of a construction permit under 10 CFR Part 50, who is also to be the holder of a license under 10 CFR Part 70 authorizing the ownership and possession for storage only of special nuclear material at the reactor construction site for future use as fuel in the reactor (after issuance of an operating license under 10 CFR Part 50), shall, during the interim storage period prior to licensed operation, have and maintain financial protection in the amount of $1,000,000 and execute an indemnity agreement with the Commission. Proof of financial protection is to be furnished prior to, and the indemnity agreement executed as of, the effective date of the 10 CFR Part 70 license. Payment of an annual indemnity fee is required.

The Consolidated Edison Company, is with respect to Indian Point Unit 2, subject to the foregoing requirements, and has taken the following steps with respect thereto.

The Company has furnished to the Commission proof of financial protection in the amount of $1,000,000 in the form of a Nuclear Energy Liability Insurance Association policy (Nuclear Energy Liability Policy, facility form) Nos. NF-100.

Further, the Company executed Indemnity Agreement No. B-19 with the Commission as of January 12, 1962, which was amended to cover its pertinent preoperational fuel storage under license SNM-1108 on March 4, 1969. The Company has paid the annual indemnity fee applicable to preoperational fuel storage.

17.2 Operating License

Under the Commission's regulations, 10 CFR Part 140, a license authorizing the operation of a reactor may not be issued until proof of financial protection in the amount required for such operation has been furnished, and an indemnity agreement covering such operation (as distinguished from, preoperational fuel storage only) has been executed. The amount of financial protection which must be maintained for reactors which have a rated capacity of 100,000 electrical kilowatts or more is the maximum amount available from private sources, i.e., the combined capacity of the two nuclear liability insurance pools, which amount is currently $82 million.

Accordingly, no license authorizing operation of Indian Point Unit 2 will be issued until proof of financial protection in the requisite amount has been received and the requisite indemnity agreement executed.

We expect that, in accordance with the usual procedure, the nuclear liability insurance pools will provide, several days in advance of anticipated issuance of the operating license document, evidence in writing, on behalf of the applicant, that the present coverage has been appropriately amended and that the policy limits have been increased, to meet the requirements of the Commission's regulations for reactor operation. The amount of financial protection required for a reactor having the rated capacity of this facility would be $82 million. Consolidated Edison Company will be required to pay an annual fee for operating license indemnity as provided in our regulations, at the rate of $30 per each thousand kilowatts of thermal capacity authorized in its operating license.

On the basis of the above considerations, we conclude that the presently applicable requirements of 10 CFR Part 140 have been satisfied and that, prior to issuance of the operating license, the applicant will be required to comply with the provisions of 10 CFR Part 140 applicable to operating licensees, including those as to proof of financial protection in the requisite amount and as to execution of an appropriate indemnity agreement with the Commission.

18.0 CONCLUSIONS

Based on our evaluation of the application as set forth above, we have concluded that:

1. The application for facility license filed by the Consolidated Edison Company of New York, Inc., dated December 6, 1965, as amended (Amendments Nos. 9 through 25, dated October 15, 1968, October 13, 1969, October 24, 1969, November 21, 1969, December 29, 1969, January 27, 1970, March 2, 1970, March 30, 1970, April 17, 1970, June 3, 1970, July 14, 1970, July 17, 1970, July 28, 1970, July 29, 1970, August 13, 1970, August 28, 1970, and November 12, 1970, respectively) complies with the requirements of the Atomic Energy Act of 1954, as amended (Act), and the Commission's regulations set forth in 10 CFR Chapter 1; and
2. Construction of the Indian Point Nuclear Generating Unit No. 2 (the facility) has proceeded and there is reasonable assurance that it will be completed, in conformity with Provisional Construction Permit No. CPPR-21, the application as amended, the provisions of the Act, and the rules and regulations of the Commission; and
3. The facility will operate in conformity with the application as amended, the provisions of the Act, and the rules and regulations of the Commission; and

4. There is reasonable assurance (i) that the activities authorized by the operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the regulations of the Commission set forth in 10 CFR Chapter 1; and
5. The applicant is technically and financially qualified to engage in the activities authorized by this operating license, in accordance with the regulations of the Commission set forth in 10 CFR Chapter 1; and
6. The applicable provisions of 10 CFR Part 140 have been satisfied; and
7. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public.

Prior to any public hearing on the matter of the issuance of an operating license to Consolidated Edison for Indian Point Unit No. 2, the Commission's Division of Compliance will prepare and submit a supplement to this Safety Evaluation which will deal with those matters relating to the status of construction completion and conformaty of this construction to the provisional construction permit and the application. Before an operating license will be issued to Consolidated Edison for Indian Point Unit No. 2, assuming such a license is authorized following the public hearing, the facility must be completed in conformity with the provisional construction permit, the application, the Act, and the rules and regulations of the Commission. Such completeness of construction as is required for safe operation at the authorized power level must be verified by the Commission's Division of Compliance prior to license issuance.

APPENDIX A

CHRONOLOGY OF

REGULATORY REVIEW OF THE CONSOLIDATED EDISON COMPANY

INDIAN POINT NUCLEAR GENERATING PLANT UNIT NO. 2

(SUBSEQUENT TO CONSTRUCTION PERMIT NO. CPPR-21

ISSUED ON OCTOBER 14, 1966)

1.	April 17, 1967	Submittal of Amendment No. 6 containing design information on the Emergency Core Cooling System and other areas as requested by the ACRS in their letter to the Chairman AEC, of 8/16/66.
2.	July 18, 1967	Meeting with applicant to discuss revised design of Emergency Core Cooling System and other areas as per Amendment No. 6.
3.	August 2, 1967	Letter to applicant requesting additional information on subjects addressed by the ACRS in their letter of 8/16/66.
4.	October 16, 1967	Submittal of Amendment No. 7 in response to DRL request of August 2, 1967.
5.	October 31, 1967	Submittal of Amendment No. 8, revised pages for Amendment No. 7.
6.	December 28, 1967	ACRS Subcommittee meeting to discuss emergency core cooling system, reactor pit crucible, primary coolant system, other areas.
7.	January 30, 1968	Submittal of "Report on the Containment Building Liner Plate Buckle in the Vicinity of the Fuel Transfer Canal".
8.	February 2, 1968	Meeting with applicant to discuss content of Amendments No. 6, 7, and 8.
9.	February 13, 1968	Meeting with applicant to complete discussion of February 2, 1968.

10.	March 8, 1968	ACRS Full Committee meeting to discuss Emergency Core Cooling System; reactor internals; primary coolant system, design, fabrication, in-service inspection, and leak detection; core design; reactor pit crucible; and containment liner quality control and stress analysis.
11.	October 15, 1968	Consolidated Edison Company filed application for an Operating License for the IP-2 Plant. Amendment 9, Volumes 1, 2, 3, & 4.
12.	March 5, 1969	AEC-DRL requested additional information on medical and emergency plans.
13.	March 12, 1969	AEC-DRL staff met with Con Ed personnel to discuss scheduling of regulatory review of application for operating license.
14.	April 3, 1969	AEC-DRL staff met with Con Ed personnel to discuss structural and seismic design and tornado protection.
15.	April 16, 1969	AEC-DRL staff met with Con Ed to discuss accidental and normal radioactivity release from the IP-2 plant.
16.	April 28, 1969	Con Ed requested extension of completion date for construction of the IP-2 plant.
17.	May 2, 1969	AEC-DRL staff and Nathan M. Newmark, seismic design consultant, met with Con Ed personnel at the IP-2 site to discuss seismic design and review status of construction and site inspection.
18.	May 19, 1968	AEC-DRL staff issued an order extending completion date for construction of the IP-2 plant to June 1, 1970.

19.	August 4, 1969	Request to applicant for additional information on site and environment, reactor coolant system, containment system, engineered safety features, instrumentation and control, electrical systems, waste disposal and radiation protection, conduct of operations, and accident analysis.
20.	August 22, 1969	AEC-DRL staff requests copies of monitoring reports and status of actions on Fish and Wildlife recommendations.
21.	August 23, 1969	ACRS Subcommittee meeting on tornado protection, emergency planning, permanent incore instrumentation, adequacy of onsite emergency power, and containment isolation.
22.	September 24, 1969	Meeting with applicant to discuss Westinghouse presentation on power distribution detection and control in Indian Point 2.
23.	October 13, 1969	Submittal of Amendment 10 (Supplement #1) responses to AEC regulatory staff's request of March 5, 1969, on medical plans and partial answers to AEC regulatory staff's request for additional information of August 4, 1969.
24.	October 24, 1969	Submittal of Amendment No. 11, replacement pages and responses to AEC regulatory staff's request for additional information of August 4, 1969, on Sections 1, 4, 5, 6, 7, 12, and 14 of the FSAR.
25.	November 13, 1969	Request for additional information on reactor, reactor coolant system, containment system, engineered safety features, auxiliary and emergency systems, initial tests and operations, and accident analysis.
26.	November 21, 1969	Submittal of Amendment No. 12, additional and replacement pages to be inserted into the FFDSAR and further responses to AEC regulatory staff's request for additional information of 8/4/69 on Sections 1, 4, 7, 8 and 11 of the FFDSAR.

27.	December 10, 1969	Meeting with applicant to review electrical drawings including AC power, DC power, Reactor Protection System, and Engineered Safety Features.
28.	December 30, 1969	Meeting with applicant and Westinghouse Electric Corporation to continue detailed review of electrical drawings including Reactor Protection System and Engineered Safety Features.
29.	January 16, 1970	Meeting with applicant to review and discuss electrical drawings including Reactor Protection System and Engineered Safety Features.
30.	January 21, 1970	Meeting with applicant & Westinghouse Electrical Corporation on technical specifications.
31.	January 27, 1970	Submittal of Amendment No. 14, replacement pages for FSAR & further responses to AEC-DRL questions of 8/4/69 & 11/13/69, chapters 1, 4, 6, 11, 12 & 14.
32.	February 17, 1970	Meeting with applicant for presentation of results of Con Ed's Analysis concerning potential damage to Indian Point 2 and IP-3 from a failure of the IP-1 superheater stack.
33.	March 2, 1970	Submittal of Amendment No. 15, responses to AEC regulatory staff's requests for additional information of 8/4 and 11/13, 1969 and Containment Design Report.
34.	March 10, 1970	Request to applicant for additional financial data.
35.	March 13, 1970	Meeting with applicant to discuss questions concerning core heat transfer and burnout limits, fuel element performance and ECCS performance during a LOCA.

36.	March 19, 1970	Meeting with applicant, Westinghouse presentation on iodine removal system for IP-2.
37.	March 26, 1970	Meeting with applicant to discuss analysis of fresh water flood and changes to electrical systems.
38.	March 30, 1970	Submittal of Amendment No. 16, additional and replacement pages for the FSAR and further responses to the AEC regulatory staff's request for additional information of August 4 and November 13, 1969.
39.	April 25, 1970	ACRS Subcommittee meeting and meeting with applicant on instrumentation and control, and anticipated transients with failure to scram.
40.	April 17, 1970	Submittal of Amendment No. 17, additional and replacement pages to be inserted into the FSAR and further responses to AEC regulatory staff's request for additional information of August 4 and November 13, 1969.
41.	April 29, 1970	Meeting with applicant to discuss seismic and structural design questions for IP-2.
42.	May 5, 1970	Meeting with applicant to discuss failure mode analysis of the engineered safety feature manual actuation panel.
43.	May 11, 1970	ACRS Subcommittee meeting at the Indian Point 2 site to discuss instrumentation and control and Electrical Systems.
44.	May 12, 1970	AEC issued Order extending completion date for construction of the IP-2 plant to June 1, 1971.
45.	May 28, 1970	ACRS Subcommittee meeting to discuss loss-of-coolant accident, anticipated transients with failure to scram.
46.	June 3, 1970	Submittal of Amendment No. 18, additional and revised pages for the FSAR in response to AEC regulatory staff request for additional information.

47.	June 11, 1970	ACRS full Committee meeting to consider design of engineered safety feature manual actuation panel and operation with less than four loops.
48.	June 17, 1970	Meeting with applicant to discuss consequences of turbine missiles, sensitized stainless steel control room accident dose, hydrogen recombiner.
49.	July 15, 1970	Submittal of Amendment No. 19 (Supplement 10), additional and revised pages for the FSAR and Flooding Evaluation report.
50.	July 20, 1970	Submittal of Amendment No. 20, (Supplement 11) proposed Technical Specifications.
51.	July 24, 1970	Request for additional information on emergency core cooling, reactor coolant system, instrumentation and control, electrical systems, conduct of operations and accident analysis.
52.	July 28, 1970	Submittal of Amendment No. 21, Con Ed Annual Report.
53.	July 28 and 29, 1970	ACRS Subcommittee meeting to discuss technical specifications, flood protection, Unit No. 1 superheater stack failure and containment sprays.
54.	July 30, 1970	Submittal of Amendment No. 22, (Supplement 12), revised pages for FSAR in response to request for additional information.
55.	August 7, 1970	Meeting with applicant to discuss technical specifications.
56.	August 13, 1970	ACRS full Committee meeting to discuss the matters addressed in our July 2, 1970 report.
57.	August 14, 1970	Submittal of Amendment No. 23 (Supplement 13), answers to request for additional information issued July 24.

58.	August 18, 1970	Meeting to discuss licensed operator requirements.
59.	August 28, 1970	Submittal of Amendment No. 24 (Supplement 14). Revised pages to the FSAR.
60.	September 1, 1970	Meeting with applicant regarding performance of Emergency Core Cooling System.
61	September 9, 1970	Meeting with the applicant to discuss Technical Specifications.
62.	October 21, 1970	Request to applicant for a report on analysis of laminations in base plate material of the IP-2 pressurizer.
63.	October 29, 1970	Meeting with applicant to review technical specifications for the Indian Point 2 plant.
64.	November 1970	Submittal of Amendment 25 (Supplement 15), changes to technical specifications and to FSAR.

APPENDIX B

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
UNITED STATES ATOMIC ENERGY COMMISSION
WASHINGTON, D.C. 20545

SEP 23 1970

Honorable Glenn T. Seaborg
Chairman
U. S. Atomic Energy Commission
Washington, D. C. 20545

Subject: REPORT ON INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

Dear Dr. Seaborg:

At its 125th meeting, September 17-19, 1970, the Advisory Committee on Reactor Safeguards completed its review of the application by Consolidated Edison Company of New York, Inc., for authorization to operate the Indian Point Nuclear Generating Unit No. 2. This project had previously been considered at the Committee's 95th, 98th, 122nd, and 124th meetings, and at Subcommittee meetings on August 23, 1969, March 13, 1970, April 25, 1970, May 28, 1970, July 28-29, 1970, and September 15, 1970. Subcommittees also met at the site on December 28, 1967 and May 11, 1970. The Committee last reported on this project to you on August 16, 1966. During the review, the Committee had the benefit of discussions with representatives of the Consolidated Edison Company and their contractors and consultants, and with representatives of the AEC Regulatory Staff. The Committee also had the benefit of the documents listed.

The Indian Point site is located in Westchester County, New York, approximately 24 miles north of the New York City limits. The minimum radius of the exclusion area for Unit No. 2 is 520 meters and Peekskill, the nearest population center, is approximately one-half mile from the unit. Also at this site are Indian Point Unit 1, which is licensed for operation at 615 MWt, and Unit 3, which is under construction.

The applicant has re-evaluated flooding that could occur at the site in the event of the probable maximum hurricane and flood, in the light of more recent information, and has concluded that adequate protection exists for vital components and services.

Additional seismic reinforcement being provided for the Indian Point Unit No. 1 superheater building and removal of the top 80 ft. of the superheater stack will enable the stack to withstand winds in the range of 300-360 mph corresponding to current tornado design criteria. Since

the reinforcement of the superheater building, which supports the stack, enables the stack to resist wind loads of a magnitude most likely to be experienced from a tornado, the Committee believes that removal of the top 80 ft. of the stack, to enable it to resist the maximum effects from a tornado, may be deferred until a convenient time during the next few years, but prior to the commencement of operation of Indian Point Unit No. 3. The applicant has stated that truncation of the stack will have no significant adverse effect on the environment.

The Indian Point Unit No. 2 is the first of the large, four-loop Westinghouse pressurized water reactors to go into operation, and the proposed power level of 2758 MWt will be the largest of any power reactor licensed to date. The nuclear design of Indian Point Unit No. 2 is similar to that of H. B. Robinson with the exception that the initial fuel rods to be used in Indian Point Unit No. 2 will not be prepressurized. Part-length control rods will be used to shape the axial power distribution and to suppress axial xenon oscillations. The reactor is designed to have a zero or negative moderator coefficient of reactivity, and the applicant plans to perform tests to verify that divergent azimuthal xenon oscillations cannot occur in this reactor. The Committee recommends that the Regulatory Staff follow the measurements and analyses related to these tests.

Unit 2 has a reinforced concrete containment with an internal steel liner which is provided with facilities for continuous pressurization of weld and penetration areas for leak detection, and a seal-water system to back up piping isolation valves. In the unlikely event of an accident, cooling of the containment is provided by both a containment spray system and an air-recirculation system with fan coolers. Sodium hydroxide additive is used in the containment spray system to remove elemental iodine from the post-accident containment atmosphere. An impregnated charcoal filter is provided to remove organic iodine.

Major changes have been made in the design of the emergency core cooling system as originally proposed at the time of the construction permit review. Four accumulators are provided to accomplish rapid reflooding of the core in the unlikely event of a large pipe break, and redundant pumps are included to maintain long-term core cooling. The applicant has analyzed the efficacy of the emergency core cooling system and concludes that the system will keep the core intact and the peak clad temperature well below the point where zircaloy-water reaction might have an adverse effect on clad ductility and, hence, on the continued structural integrity of the fuel elements. The Committee believes that there is reasonable assurance that the Indian Point Unit No. 2 emergency core cooling system will perform adequately at the proposed power level.

The Committee concurs with the applicant that the reactor pit crucible, proposed at the time of the construction permit review, is not essential as a safety feature for Indian Point Unit No. 2 and need not be included.

To control the concentration of hydrogen which could build up in the containment following a postulated loss-of-coolant accident, the applicant has provided redundant flame recombiner units within the containment, built to engineered safety feature standards. Provisions are also included for adequate mixing of the atmosphere and for sampling purposes. The capability exists also to attach additional equipment so as to permit controlled purging of the containment atmosphere with iodine filtration. The Committee believes that such equipment should be designed and provided in a manner satisfactory to the Regulatory Staff during the first two years of operation at power.

The applicant plans to install a charcoal filter system in the refueling building to reduce the potential release of radioactivity in the event of damage to an irradiated fuel assembly during fuel handling. This installation will be completed by the end of the first year of full power operation.

The reactor instrumentation includes out-of-core detectors, fuel assembly exit thermocouples, and movable in-core flux monitors. Power distribution measurements will also ordinarily be available from fixed in-core detectors.

The applicant has proposed that a limited number of manual resets of trip points, made deliberately in accordance with explicit procedures, by approved personnel, independently monitored, and with settings to be calibrated and tested, should provide an acceptable basis for the occasional operation of Indian Point Unit No. 2 with only three of the four reactor loops in service. The Committee concurs in this position.

The applicant stated that neutron noise measurements will be made periodically and analyzed to provide developmental information concerning the possible usefulness of this technique in ascertaining changes in core vibration or other displacements. On a similar basis, accelerometers will be installed on the pressure vessel and steam generators to ascertain the practicality of their use to detect the presence of loose parts.

The reactor includes a delayed neutron monitor in one hot leg of the reactor coolant system to detect fuel element failure. Suitable operability requirements will be maintained on the several sensitive means of primary system leak detection.

A conservative method of defining pressure vessel fracture toughness should be employed that is satisfactory to the Regulatory Staff.

The applicant stated that existing experimental results and analyses provide considerable assurance that high burnup fuel of the design employed will be able to undergo anticipated transients and power perturbations without a loss of clad integrity. He also described additional experiments and analyses to be performed in the reasonably near future which should provide further assurance in this regard.

The Committee has, in recent reports on other reactors, discussed the need for studies on further means of preventing common failure modes from negating scram action, and of possible design features to make tolerable the consequences of failure to scram during anticipated transients. The applicant has provided the results of analyses which he believes indicate that the consequences of such transients are tolerable with the existing Indian Point Unit No. 2 design at the proposed power level. Although further study is required of this general question, the Committee believes it acceptable for the Indian Point Unit No. 2 reactor to operate at the proposed power level while final resolution of this matter is made on a reasonable time scale in a manner satisfactory to the Regulatory Staff. The Committee wishes to be kept advised.

Other matters relating to large water reactors which have been identified by the Regulatory Staff and the ACRS and cited in previous ACRS letters should, as in the case of other reactors recently reviewed, be dealt with appropriately by the Staff and the applicant in the Indian Point Unit No. 2 as suitable approaches are developed.

The ACRS believes that, if due regard is given to the items recommended above, and subject to satisfactory completion of construction and preoperational testing of Indian Point Unit No. 2, there is reasonable assurance that this reactor can be operated at power levels up to 2758 MWt without undue risk to the health and safety of the public.

Sincerely yours,

Original Signed by
Joseph M. Hendrie

Joseph M. Hendrie
Chairman

References attached.

References - Indian Point Nuclear Generating Unit No. 2

1. Amendment No. 9 to Application of Consolidated Edison Company of New York for Indian Point Nuclear Generating Unit No. 2, consisting of Volumes I - IV, Final Safety Analysis Report, received October 16, 1968

2. Amendments 10 - 20 to the License Application
3. Amendments 22 - 24 to the License Application

APPENDIX C

Comments on

Indian Point Nuclear Generating Unit No. 2
Consolidated Edison Company of New York, Inc.
Final Facility Description and Safety Analysis Report
Volumes I, II, III and IV dated October 15, 1968

Prepared by

Air Resources Environmental Laboratory
Environmental Science Services Administration
November 29, 1968

As pointed out in our comments of October 29, 1965 on Unit No. 2, a primary influence on the meteorological statistics of the Indian Point site seems to be its location in a river valley about a mile wide with terrain rising 600 to 1000 feet on either side. Consequently, wind directions follow a pronounced diurnal cycle with daytime, unstable (lapse) flow in the upriver direction and nighttime, stable flow in the downriver directions. The report documents a 42.4 percent inversion frequency, but it should also be pointed out that inversion conditions are largely confined to the nighttime, downriver flow lasting about 12 hours before changing to lapse or upriver flow. Figure 2.6-1, although in terms of average vectors, shows the marked wind reversals at sunset and sunrise and the rather persistent, channeled flow that can occur during the middle of the night (see the mean direction between 0200 and 0800 hours). The mean wind speeds during this persistent period is about 2.5 m/sec which indicates that 50 percent of the time inversion wind speeds could be less than 2.5 m/sec.

In the absence of specific, joint-frequency wind speed and direction persistence data from the site, a reasonably conservative meteorological model would be to assume for a ground release a 1 m/sec wind speed under inversion conditions in a persistent downriver direction for a period of 8 hours. Taking into account the likelihood of a diurnal wind reversal, a very conservative assumption would be to allow the plume centerline to meander over a 22-1/2° arc under the same conditions for the remainder of the 24-hour period. Again, with no specific on-site wind persistence data, the conservative assumption has been made.

The amount of additional atmospheric diffusion because of the building turbulence can be assessed by the virtual point source expression $[(x + x_o)/x]^{1.5}$ as used by the applicant, which for a value of $x_o = 430$ m

amounts to a factor of 2.5 at the site boundary (520 m) and 1.6 at the low population boundary (1100 m). These values are in close agreement with the method of using a shape factor of 1/2 and a building cross-section of 2000 m^2.

In summary, from data presently available, it would seem reasonably conservative to assume a persistent wind direction for an 8-hour period under inversion conditions and a 1 m/sec wind speed. With the added assumption of a building wake shape factor of 1/2 and a cross-sectional area of 2000 m^2, the resulting 0-8 hr relative concentration would be 6.6×10^{-4} sec m^3 at the site boundary and 3.7×10^{-4} at the low population boundary. From Table 14.3.5-3 one can calculate that the applicant's model for the 0-8 hr period results in an average relative concentration of 4.8×10^{-4} and 2.4 sec m^{-3} at the site and low population boundary, respectively.

APPENDIX C

Comments on

Indian Point Nuclear Generating Unit No. 2
Consolidated Edison Company of New York, Inc.
Final Facility Description and Safety Analysis
Amendment No. 12 dated November 21, 1969, and
Amendment No. 14 dated January 27, 1970

Prepared by

Air Resources Environmental Laboratory
Environmental Science Services Administration
February 17, 1970

The original documentation of the Indian Point site during the period 1955-1957 indicates that at the 100-ft. height the annual prevailing wind direction is from the north northeast and that in the sector from 22.5 to 42.5 degrees the frequency of inversion, neutral and lapse conditions was 6, 2, and 1 percent, respectively. Within this sector, the shortest site boundary is approximately in a direct line through Units 2 and 3 at a distance of 610 and 380 m, respectively, as measured from figure 2.2-2. It is about 500 m from the Unit 1 stack to this common boundary point. The nearest site boundary, regardless of sector, is where the property line intersects the downriver edge of the site. Although this point is at a distance of 580 m from Unit 2, it is not in the most prevalent wind direction by a considerable amount.

To compute the average annual dilution factor we have assumed the frequencies listed above, averaged over a 20-degree sector with a wind speed of 2, 4 and 6 m/sec, respectively, for inversion (Type F), neutral (Type D), and lapse (Type B) conditions. Assuming no building wake effect our results show the applicant's values for Units 1 and 2 to be reasonably conservative. In the case of Unit 3 we compute an average annual dilution factor of 2.9×10^{-5} sec m^{-3} as compared to the applicant's value of 1.6×10^{-5} sec m^{-3}. The only explanation we have for the ESSA value being twice as high is the use of the building wake effect in the applicant's assumptions.

It is our view that the use of the building wake effect in the long-term average diffusion equation, as was done by the applicant, is inappropriate. It does not seem logical that for the same atmospheric conditions the Sutton equation on page Q 11.10-1 for the long-term model gives <u>more</u> credit for building wake effect than the equivalent short-term model on p. Q 11.10-2. For example at $x = 400$ m assuming $x_0 = 400$ m and $n = 0.5$, the building wake effect, $[(x+x_0)/x]^{2-n/2}$, for the long-term equation is 3.4 whereas for the effect in the short-term equation, $[(x+x_0)/x]^{2-n}$, the value is 2.8. It is the larger exponent in the former that makes the difference. Also, the fact that one averages in the horizontal dimension over a sector essentially would nullify any added dilution in that dimension because of wake effect.

DEPARTMENT OF THE ARMY
COASTAL ENGINEERING RESEARCH CENTER
5201 LITTLE FALLS ROAD, N.W.
WASHINGTON, D.C. 20016

CERER

21 November 1969

Mr. Roger S. Boyd
Asst. Director for Reactor Projects
Division of Reactor Licensing
U. S. Atomic Energy Commission
Washington, D. C. 20545

Dear Mr. Boyd:

Reference is made to your letters regarding Docket Nos. 50-247, 50-286, 50-342, and 50-343, Consolidated Edison Company of New York's proposed Indian Point Nuclear Generating Units No. 2 and No. 3, and Units No. 4 and No. 5 which are contiguous to Indian Point plant site.

Pursuant with our arrangements, Mr. R. A. Jachowski and Mr. B. R. Bodine of CERC have reviewed all pertinent information contained in the reports from the standpoint of establishment of a design water level. This included the review of the storm surge associated with the Probable Maximum Hurricane (PMH) and wind wave analysis.

We concur with the applicant's finding that the design water level should be 14.5 feet above the mean sea level datum for Units, Nos. 2, 3, 4 and 5. Although this value is acceptable, there are compensating errors in routing procedure employed.

If you have any further questions regarding this matter please let us know.

Sincerely yours,

Edward M. Willis

EDWARD M. WILLIS
Lieutenant Colonel, CE
Director

APPENDIX E

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
WASHINGTON, D.C. 20242

SEP 16 1970

Mr. Harold Price
Director of Regulation
U.S. Atomic Energy Commission
7920 Norfolk Avenue
Bethesda, Maryland 20545

Dear Mr. Price:

Submitted herewith in response to a request by R. C. DeYoung is a review of the flood information presented in Amendment No. 19 to the Final Safety Analysis Report for Unit No. 2 Indian Point Nuclear Generating Station. It is presumed that the flood levels for all 3 units at the Indian Point Stations will be based on this amendment. Copies of our earlier reviews, for Unit No. 2 (Aug. 15, 1966) prepared by E. L. Meyer, and for Unit No. 3 (January 6, 1969) prepared by P. J. Carpenter, are attached.

This review was prepared by P. J. Carpenter and has been discussed with members of your staff. We have no objection to your making this review a part of the public record.

Sincerely yours,

W. A. Nathan

Acting Director

Enclosures

Consolidated Edison Company of New York Inc.
Indian Point Nuclear Generating Station Unit No. 2
Docket No. 50-247

The probable maximum flood as defined by the U.S. Army Corps of Engineers, at the site, has been calculated as 1,[illegible],000 cubic feet per second. This discharge is approximately five times greater than the maximum observed flood at Green Island, and is approximately twice the maximum discharge observed for nearby [illegible]-sized drainage basins which appear to exhibit similar runoff characteristics. The stage for the maximum probable flood at the site, computed using standard step-backwater procedures, is given as varying between 13.4 and 14.0 ft msl (mean sea level) depending on concurrent tide levels at the Battery. It is shown that none of the dams on the Hudson River and its tributaries would fail during the probable maximum flood. The above results were obtained using conservative assumptions and appear to be reasonable.

The analyses show that the occurrence of the probable maximum flood on Esopus Creek would cause failure of Ashokan Dam some 75 miles upstream of the site. To establish a flood design level at Indian Point various combinations of the following factors were considered: 1) the flow resulting from the Ashokan Dam failure, 2) various concurrent Hudson River flood flows, and 3) various concurrent tide levels at the Battery. The results of these combinations of factors were compared with the stage of the probable maximum flood (14.0 ft msl) and the stage resulting from the probable maximum hurricane plus spring high tide (14.5 ft msl). The most critical combination investigated consisted of the flows from the Ashokan Dam failure caused by the probable maximum flood on Esopus Creek, the concurrent standard project flow (one half the probable maximum flood), the concurrent stage at the Battery corresponding to the standard project hurricane tide level and wind waves of one foot at the site. This stage is given as 15.0 ft msl. The lowest floor elevation of Unit No. 2 is given as 15.25 ft msl.

Other combinations of the above-mentioned factors, such as Ashokan Dam failure and the standard project hurricane or floods larger than the standard project flood on the Hudson River, could produce higher stages at the site. Depending on the degree of conservatism desired, any of these higher stages could also be selected as the design flood level. However, the stage for the combination selected for the design flood level exceeds those given for the probable maximum flood or probable maximum hurricane when these are considered as independent events.

NATHAN M. NEWMARK
CONSULTING ENGINEERING SERVICES

APPENDIX F

1114 CIVIL ENGINEERING BUILDING
URBANA, ILLINOIS 61801

REPORT TO THE AEC REGULATORY STAFF

STRUCTURAL ADEQUACY

OF

INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

Consolidated Edison Company of New York, Inc.

Docket No. 50-247

By

N. M. Newmark
and
W. J. Hall

Urbana, Illinois

20 August 1970

1

REPORT TO THE AEC REGULATORY STAFF

STRUCTURAL ADEQUACY

OF

INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

INTRODUCTION

This report is concerned with the structural adequacy of the containment structures, piping, equipment and other critical components for the Indian Point Nuclear Generating Unit No. 2 for which application for a construction permit and an operating license has been made to the United States Atomic Energy Commission by the Consolidated Edison Company of New York, Inc. The facility is located on the east bank of the Hudson River at Indian Point, village of Buchanan, in upper Westchester County, New York. The site is about 24 miles N of the New York City boundary and 2.5 miles SW of Peeksill, New York.

This report is based on a review of the Final Facility Description and Safety Analysis Report (Ref. 1) and the containment design report (Ref. 2). The report also is based in part on the discussion and inspection resulting from the visit to the site on 2 May 1969 by N. M. Newmark and W. J. Hall in conjunction with Mr. K. Kniel and Mr. M. McCoy of AEC-DRL. A number of topics were discussed with the applicant and his consultants at the time of this visit, and subsequently additional information has become available through supplements to the FSAR and through discussions with the personnel of DRS, DRL, and the applicant and his consultants. A discussion of the adequacy of the structural criteria presented in the Preliminary Safety Analysis Report is contained in our report of August 1966 (Ref. 3), and unless otherwise noted no comment will be made in this report concerning points covered there.

2

The design criteria for the containment system and Class I components for this plant called for a design to withstand a Design Basis Earthquake of 0.15g maximum horizontal ground acceleration coupled with other appropriate loadings to provide for containment and safe shut down. The plant was also to be designed for an Operating Basis Earthquake of 0.1g maximum horizontal ground acceleration simultaneously with the other appropriate loads forming the basis of containment design.

COMMENTS ON ADEQUACY OF DESIGN

Dynamic Analyses

(a) Containment Building. The answer to Question 1.9 of the FSAR indicates that only the containment building, the primary auxiliary building, and the electric cable tunnel were designed with the use of semi-formal dynamic analyses. A description of the method of analysis employed is given briefly in Section 5.1.3.8 of the FSAR and in Section 3.1.5 of the containment design report. The procedure employed involved a calculation of the fundamental frequency and mode shape by use of a modified Rayleigh method. The base shear for the structure was computed from the period and the spectral response corresponding to the appropriate degree of damping. The base shear was then applied as a loading to the structure as an inverted triangular loading. The shears at the nodes were used to calculate the moments and displacements at various points in the structure. For the structures involved it is believed that the approach leads to a design which is reasonably adequate.

A similar approach was followed for the primary auxiliary building as described in the answer to Question 1.9. It is noted there that a one-third increase over working stress was allowed in the design of the bracing in the

case of the Design Basis Earthquake. This stress is below yield, and it is believed that the design will prove to be satisfactory.

(b) Other Buildings and Equipment. The discussion presented in answer to Question 1.9 of the FSAR for other buildings and equipment such as the control building, fan house, intake structure, etc., indicate that a refined static approach was used, which involves employing the peak value from the appropriate response spectrum curve for a given value of damping and multiplying this by the appropriate mass to obtain the inertial loading. From the description given for the various buildings and items of equipment, and the modeling techniques employed, it is concluded that the inertial loadings used in design are reasonably close to those that might be obtained with a more sophisticated analysis and lead to reasonable design values.

The submission in Question 1.3 of Supplement 13 indicates that the Turbine Building, and Fuel Storage Building Structure above the Fuel Storage Pit were reanalyzed by a multi-degree-of-freedom modal dynamic analysis method to check their adequacy. As a result of this reanalysis, the applicant advises that certain structural modifications will be made to columns and cross bracing in the Turbine Building to insure that it can withstand the DBE. The superstructure of the fuel storage building was ascertained to be adequately designed, without modification to withstand the effects of the DBE. The applicant states that reanalysis of the strengthened turbine building and superheater building for Indian Point No. 1 does not significantly affect the responses calculated for the original structures.

(c) Piping Analysis. The method used by the applicant for analysis of the piping, as described in the answer to Question 1.6 of the FSAR, is the same as was used in Ginna. The peak ground response spectrum value for 0.5 percent damping was used, applied as static accelerations in each direction

separately, and the resulting stresses superposed. It was assumed by the applicant that the piping was supported along rigid systems and therefore not subjected to amplified ground motion at points of support. The system was analyzed with the anchors and supports as actually used, according to the discussion presented to us during the time of our visit in May,1969. It was the view of the applicant that the thermal motions were greater than any differential ground displacements and the latter therefore are not critical items in the design. In answer to Question 1.13 (Suppl. 13) the applicant advises that relative seismic displacement was considered for the main steam lines, where the largest relative displacements are expected; stress differentials of less than 10% resulted. Also, seismic supports installed to date are those specified in the design and employed in the analyses; where deviations in supports must occur, reanalysis will be carried out. These results and approaches appear satisfactory to us.

Since this plant was designed before recent developments and changes in piping design specifications, the 1968 ASME Addenda were not applied. Blow-down and earthquake were considered as separate items and not combined in this design. We are advised that the response to Question 1.9 of Supplement 12 states that a review of the Indian Point 3 reactor coolant system which is identical to Indian Point 2, for combined earthquake and blow-down indicates that the design is adequate.

It is stated in the answer to Question 1.6 of the FSAR that the approach resulted in a seismic design load approximately equal to 0.60W horizontally and 0.40W vertically taken simultaneously. It is further stated that for the Design Basis Earthquake the sum of the resulting additional stress plus the normal stresses was limited to 1.2 times the B31.1 code

allowable stresses. In a similar manner the stresses in the pipe supports and hangers were limited to 1.2 times code allowable stresses.

The applicant originally made use of the maximum spectrum value only and no modal analyses were made; in other words only a static analysis with uniform accelerations was made. Consideration was not given to modified distribution of the inertial loading to take account of the combination of modal effects.

The response to Question 1.9 of Supplement 8, describing more detailed analyses of the reactor coolant system, feedwater lines, surge lines and typical steam lines by more formal methods as carried out later lends confirmation to the adequacy of the design. On this basis, there is reason to believe that the design is adequate.

Backfill Surrounding Containment Vessel

Nine feet of crushed rock backfill was placed between the external wall of the reinforced concrete containment vessel and the retaining wall holding back the rock on the uphill side. This crushed rock backfill is drained at the bottom to avoid water pressure against the containment structure. The fill is approximately 60 to 70 feet higher on one side of the structure than on the other because of the slope of the rock surface. The design, as discussed in Section 3.1.5 of the containment design report, considered local inertial forces of loose rock as an added loading against the containment pressure vessel, and also considered passive pressures caused by failure of the rock along the surface behind the retaining wall. The localized loadings from these forces were considered in the design of the containment structure and the discussion presented in the containment design report provides reasonable assurance that the containment vessel is capable of resisting these localized forces.

Class I Equipment in Structures other than Class I

The turbine building is Class III and not designed for earthquake loadings. The answer to Question 1.3 of the FSAR indicates that the only Class I structures and components which are so located that they could be endangered by failure of Class III structures are the control building, main steam piping and feedwater piping, all of which could possibly be endangered by the Class III turbine building. It is further indicated there that no special provisions have been provided for protection except in the case of the main steam and feedwater lines up to the isolation valves, which are protected by the shield wall and the structural frame at the north end of the shield wall. Since these are located near the braced end of the turbine building, it is not anticipated by the applicant that there will be any structural failure in this area. Our judgment as to the adequacy of this aspect of the design is based on the statement given in the application. And, in this respect, the answer to Question 1.3 (Supplement 13) which describes the analysis and strengthening of the Turbine Building and Superheater Building for Indian Point Unit No. 1, and their ability to withstand the DBE, should give additional protection for the control room.

It is further stated that the only Class III crane whose failure could endanger any Class I function is the fuel storage building crane and that the failure of this crane will not impair a safe and orderly shutdown. The answer to Question 1.3 (Suppl. 13) indicates that the only potential for crane lift off will be in the unloaded condition with the trolley parked over the support; the applicant advises that the unloaded crane will not be parked over the pool, so no hazard exists. It is also noted in the answer to Question 1.1.3 that the manipulator crane in the containment building,

a Class III crane, is restrained from overturning and will not endanger Class I structures.

Deformation Criteria

The general stress criteria applicable to the seismic design are summarized in Appendix A of the FSAR. The statement given on page A3 of Appendix A states that for all components, systems and structures classified as Class I, the primary steady state stresses, when combined with seismic stresses resulting from the response to the Design Basis Earthquake, are limited so that the function of the component system or structure shall not be impaired so as to prevent a safe and orderly shut-down of the plant.

We were advised at the time of our inspection of the plant in May 1969 that, for normal loadings plus the Operating Basis Earthquake, the intention was to use code allowables plus the 20 percent increase for transient conditions on Class I components and systems. For the Design Basis Earthquake and blow-down, basically the same criteria were used, although originally it had been planned to adopt higher allowables going into the plastic range using the code for faulted conditions. In actuality, as described in the answer to Question 1.7 of the FSAR, the allowable stresses in the case of the Design Basis Earthquake were limited to the yield point, or slightly below (see answer to Question 1.3 of Supplement 13).

The only references that we note where there was a calculation of stresses exceeding the yield point were at several places in the containment design report where it was mentioned that the calculations indicate that there could be possible local yielding of the liner under certain loading combinations, but that this would be limited and not be expected to be of a nature as to cause concern with regard to the integrity of the liner.

Reactor Internals

The mechanical design and evaluation of the reactor core and internals is described generally in Section 3.2.3 of the FSAR. From the discussion given it appears that the core support structure and core barrel have been designed with proper attention to support points and limitations of motions. The design criteria for the internals themselves, and specifically with reference to deflections under abnormal operation, are given in Table A.3-2 of the FSAR. These appear reasonable and should provide an adequate margin of safety.

Large Penetrations

A finite element analysis of the large penetrations in the containment vessel was made by the Franklin Institute and a description of the analysis and the results obtained is presented in the containment design report. Several analyses were made for different load combinations, and in addition a number of hand calculations were made to check the order of magnitude of the expected forces and stresses and to verify that the results were reasonable Our review of the material presented, to the extent possible, indicates that the penetration design is adequate.

Splices in Large Reinforcing of Bars

Cadweld splices were used in general in the construction of the containment vessel. We were advised that the early splices, about 10 percent of the total, were made with a bronze base, and the remaining 90 percent were made with ferritic base filler metal. Around the hatch opening, we observed that there was approximately a three foot stagger of adjacent splices, but in questioning we learned that there may not be such a stagger over other areas of the containment vessel. Lack of stagger of adjacent splices could

lead to planes of weakness and cause cracking under conditions of over-loading. The pressure tests, however, will reveal any such cracking.

Approximately one in 200 splices was removed for test purposes. This is generally adequate.

Instrumentation and Controls

At the time of the May 1969 visit it was ascertained that the applicant considers the control room as a Class I structure and intends that the housing of it will also be subject to Class I requirements. However, the instrumentation for the control room as well as other instrumentation critical to containment and safe shutdown, has been purchased from the vendors according to applicant's specifications. The answer to Question 1.9 describes the vibration tests employed for selected items of essential equipment; the purpose of these tests is to help demonstrate that little or no difficulty will be expected in the operating characteristics thereof under seismic conditions. Although not absolute proof of acceptability, satisfactory test results certainly help to confirm the adequacy of such instrumentation and control items. Further information on the design and procurement approach for protection system equipment is given in the answer to Question 7.27 (Suppl. 13), and lends confirmation to the approach adopted.

Tornado Loadings

The information contained in Section 3.4 of the containment design report, and the answer to Question 5.7 of the FSAR indicates that the structure is designed for the usual wind loadings. The analyses described in Appendix B of Supplement 6, indicate that the containment building can resist the design tornado. What effect if any that a tornado could have on the control room or other critical facilities is not stated. However, the applicant states that

the siding of the control room can resist wind velocities up to 162 mph, and the girts (supporting the panels) will fail at 0.62 psi negative pressure; the building is protected by other buildings on the south and west.

Steel Liner and Containment Vessel

The analyses that have been carried out with regard to the liner are summarized in the FSAR and some additional information is presented in the containment design report. It is our understanding that where bulges of the liners occurred during construction, of less than 2 in., nothing was done to correct the bulges. However, when bulges were 2 in. or greater the liner was pushed back into a position of not more than 2 in. away from its intended position, and additional studs were used to anchor the liner in place. Temporary bracing was employed to hold it in position until the concrete was cast. Because of the foregoing, and since the temperature rise in the lower part of the structure in the liner is reduced by the use of insulating material, it is not expected that the departures from the intended original surface will lead to any difficulties.

Proof Test Procedures and Instrumentation

It is our understanding that a detailed description of the proof test procedures is to be submitted at a later date. At the time of our visit in May 1969 it was proposed by the applicant that strain readings be taken only on the liner around the penetrations. We suggested that additional readings be made which would include diameter changes of the penetrations and other measuremants that can be made conveniently and without excessive expense to provide evidence that the design meets the design criteria. Fig. 5.13-4 suggests that such readings will be made. In any event, an

interpretative report on the measurements that are taken should be provided and should be correlated with the calculations to provide evidence of validity of the design calculations.

Protection of Pipe Lines for Service Water

We were advised that pipelines for service water are embedded in the ground without any special protection. However, there appear to be alternate lines, although they are generally in the same location and/or trenches. In view of the foundation conditions surrounding the plant, and since there is no indication of previous fault motion or potential faulting, this design approach appears to be adequate. If redundancy in critical water supply is desired, it would be preferable to have separate water lines following independent routes.

Seismograph Installation

The answer to Question 1-1 of Supplement 3 indicates that one seismograph will be installed in the yard area, to provide further evidence of the extent of seismic excitation to which the plant might be subjected if an earthquake occurs. This is acceptable to us.

Containment Design Report

The containment design report, prepared for the applicant by Westinghouse Nuclear Energy Systems and United Engineers and Constructors, has proven to be helpful in arriving at an evaluation of many of the factors inherent in the design. The tables presented are useful in helping to arrive at decisions as to the adequacy of the design; we commend those responsible for the preparation of this summary type material.

We should like to encourage this type of approach to studies of the containment, structures, piping, equipment and other Class I items. We should like to urge that attention be given also to summaries and tabulation of the most important information, in terms of stresses and deformations, including the sources of the various stress components, how they were combined, and related discussion and explanatory material (including figures) which would lend itself to a much better basis for judgment as to the adequacy of design of nuclear facilities in general.

CONCLUDING REMARKS

On the basis of the information made available to us concerning the Class I structures, piping, reactor internals, and other Class I items, it is our belief that the plant possesses a reasonable margin of safety to meet the original design requirements, including the imposed Design Basis Earthquake loading conditions.

REFERENCES

1. "Final Facility Description and Safety Analysis Report -- Vols. I through V including Supplements 1, 2, 4, 5, 6, 7, 8 and 13," Indian Point Nuclear Generating Unit No. 2, Consolidated Edison Company of New York, Inc., AEC Docket No. 50-247, 1969 and 1970.

2. "Containment Design Report," for Indian Point Nuclear Generating Unit No. 2, Consolidated Edison Company of New York, Inc., prepared by Westinghouse Nuclear Energy Systems and United Engineers and Constructors, March 1969. (Labeled Final Draft)

3. "Adequacy of the Structural Criteria for Consolidated Edison Company of New York, Inc., Indian Point Nuclear Generating Unit No. 2," by N. M. Newmark and W. J. Hall, August 1966.

W. J. Hall

UNITED STATES
DEPARTMENT OF THE INTERIOR
OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

OCT 1 6 1970

Dear Mr. Chairman:

Pursuant to Section 5 of Public Law 89-605 as amended and other authorizations, we are presenting the views of the Department of the Interior in the matter of the application by the Consolidated Edison Company for an operating license for Indian Point Nuclear Generating Unit No. 2, Buchanan, New York, AEC Docket No. 50-247 (Amendment No. 9). The following comments incorporate those submitted by the Federal Water Quality Administration, the Fish and Wildlife Service and the Bureau of Outdoor Recreation.

The unit under review is the second of three units completed or being constructed at the Indian Point site. We note that applications for construction permits for two more units to be located approximately one mile south of the Indian Point site were made in June 1969.

The Department of the Interior does not object to the issuance of the operating license to the Consolidated Edison Company for Unit No. 2 of the Indian Point Nuclear Power Plant. Our position is based upon the firm commitment by the Company as expressed in its responses to the Atomic Energy Commission that it will meet the water quality standards applicable to the receiving waters and that it will take whatever steps are necessary to mitigate any harmful effects that operation of the plant may have on the fishery resources of the Hudson River and tributary waters.

The Company should be commended for the cooperation it has extended to representatives of this Department during the course of our review. The studies which the Consolidated Edison Company is presently engaged in indicate the Company's concern for the potential damages to the environment that could result from operation of this unit and the others planned at and in the vicinity of Indian Point.

We are pleased to note that the Company has made provisions to open part of its land holdings for compatible public recreation use. We express the hope that the Company's public use plans will be finalized and fully implemented at the earliest possible time.

Consolidated Edison has initiated or participated in a number of studies to determine the effects of both radiological and thermal discharges from the Indian Point reactors upon both the temperature distribution and the aquatic life of the Hudson River through its consultants, Quirk, Lawler and Matusky Engineers, and the Alden Research Laboratories of Worcester Polytechnic Institute. The Company has conducted mathematical studies of the probable temperature in the River and has checked these estimates with hydraulic model studies and actual field studies. In addition, Consolidated Edison has supported several independent but coordinated studies of the micro-organisms and aquatic life in the Hudson River and the probable effects of temperature and salinity changes upon them in the vicinity of the Indian Point Plant.

These studies are continuing and have been and will be helpful in assessing the effects of the Indian Point Unit No. 2 and of the other thermal plants which are proposed for construction on the shores of the Hudson River in the vicinity of Indian Point.

We have been provided information on plans for environmental monitoring of radiological and thermal releases proposed as a part of the operating license application. We understand that the plans for water quality monitoring, including radiological concentrations in the environment in microscopic and macroscopic aquatic life are acceptable to the State of New York. They appear reasonable and are considered generally acceptable to the Department of the Interior.

Through the monitoring programs the Company should have the necessary information to control its activities in a manner that will not violate applicable New York State as well as Federal water quality standards, recommendations of any enforcement conference or hearing board approved by the Secretary or order of any court under Section 10 of the Federal Water Pollution Control Act, and/or other State and Federal water pollution control regulations.

In view of the extensive and valuable fish and wildlife resources in the project area, it is imperative that every possible effort be made to safeguard these resources. Therefore, it is recommended that the Consolidated Edison Company be required to:

1. Continue to work closely with the Department of the Interior, New York State Department of Health, and other interested State and Federal agencies in developing plans for radiological surveys.

2. Conduct pre-operational radiological surveys as planned. These surveys should include but not be limited to the following:

   a. Gamma radioactivity analysis of water and sediment samples collected within 500 feet of the reactor effluent outfall.

   b. Beta and Gamma radioactivity analysis of selected plants and animals (including mollusks and crustaceans) collected as near the reactor effluent outfall as possible.

3. Prepare a report of the pre-operational radiological surveys and provide five copies to the Secretary of the Interior prior to project operation.

4. Conduct post-operational radiological surveys similar to that specified in recommendation (2) above, analyze the data, and prepare and submit reports every six months during reactor operation or until it has been conclusively demonstrated that no significant adverse conditions exist. Submit five copies of these reports to the Secretary of the Interior for distribution to appropriate State and Federal agencies for evaluation.

In addition to the above, the Atomic Energy Commission should urge the Consolidated Edison Company to:

1. Meet with the Department of the Interior, New York State Department of Environmental Conservation, New York State Department of Health, and other interested Federal and State agencies at frequent intervals to discuss new plans and evaluate results of the Company's ecological and engineering studies;

2. Conduct post-operational ecological surveys planned in cooperation with the above named agencies, analyze the data, prepare reports, and provide five copies of these reports to the Secretary of the Interior every six months or until the results indicate that no significant adverse conditions exist;

3. Construct, operate, and maintain fish protection facilities at the cooling water intake structure as needed to prevent significant losses of fish and other aquatic organisms; and

4. Modify project structures and operations including the addition of facilities for cooling discharge waters and reducing concentrations of harmful chemicals and other substances as may be determined necessary.

We appreciate the opportunity to provide these comments.

Sincerely yours,

Walter J. Hickel

Secretary of the Interior

Honorable Glenn T. Seaborg
Chairman, United States
Atomic Energy Commission
Washington, D. C. 20545

APPENDIX H
CONSOLIDATED EDISON COMPANY OF NEW YORK
DOCKET NO. 50-247
FINANCIAL ANALYSIS

	(dollars in millions) Calendar Year Ended Dec. 31		
	1969	1968	1965
Long-term debt	$1,981.6	$1,901.6	$1,711.0
Utility plant (net)	3,793.3	3,583.6	3,169.5
Ratio - debt to fixed plant	.52	.53	.54
Utility plant (net)	3,793.3	3,583.6	3,169.5
Capitalization	3,818.4	3,667.6	3,228.1
Ratio - net plant to capitalization	.99	.98	.98
Stockholders' equity	1,836.7	1,766.0	1,517.1
Total assets	4,069.6	3,845.4	3,387.0
Proprietary ratio	.45	.46	.45
Earnings available to common equity	93.1	95.7	89.9
Common equity	1,210.2	1,139.0	1,072.1
Rate of return on common equity	7.7%	8.4%	8.4%
Net income	127.2	128.5	111.8
Stockholders' equity	1,836.7	1,766.0	1,517.1
Rate of return on stockholders' equity	6.9%	7.3%	7.4%
Net income before interest	198.0	193.9	168.4
Liabilities and capital	4,069.6	3,845.4	3,387.0
Rate of return on total investment	4.9%	5.0%	5.0%
Net income before interest	198.0	193.9	168.4
Interest on long-term debt	84.3	77.0	62.7
No. of times fixed charges earned	2.3	2.5	2.7
Net income	127.2	128.5	111.8
Total revenue	1,028.3	982.3	840.2
Net income ratio	.124	.131	.133
Operating expenses (incl. taxes)	830.5	788.3	668.6
Operating revenues	1,028.3	982.3	840.2
Operating ratio	.81	.80	.80
Retained earnings	426.1	400.9	321.7
Earnings per share of common	$2.47	$2.57	$2.42

	1969		1968	
Capitalization at 12/31	Amount	% of Total	Amount	% of Total
Long-term debt	$1,981.6	51.9%	$1,901.6	51.9%
Preferred stock	626.6	16.4	627.0	17.1
Common stock	1,210.2	31.7	1,139.0	31.0
	$3,818.4	100.0%	$3,667.6	100.0%

Moody's Bond Ratings:
First Mortgage Bonds — A

Dun and Bradstreet Credit Rating — AaA1

EXHIBIT V

Synapse
Energy Economics, Inc.

FINANCIAL INSECURITY: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants

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Table of Contents

List of Tables and Attachments

Foreword

Where Have All the Safeguards Gone

In nuclear power's first two decades, accident insurance requirements were seriously inadequate. Decommissioning costs were overlooked entirely. The 1979 accident at Three Mile Island undermined much nuclear complacency. In the early 1980s Congress and the U.S. Nuclear Regulatory Commission made serious efforts to address these shortcomings.

The nuclear self-insurance requirement – known as the Price-Anderson Act – was increased from $560 million to the current $9.3 billion, and each plant was required to set up a dedicated decommissioning trust fund to assure that funds would be available to clean up a closed plant.

With the passage of two more decades, renewed complacency has eroded these safeguards.

This report dissects a troublesome set of developments on the cusp between economic and safety regulation, namely the rearrangement of nuclear power plant ownership into the limited liability subsidiaries of a few large companies. Because this arrangement has occurred during an era of lax and dispirited regulation, some important issues have not been pursued effectively. As a result, the consolidation of nuclear ownership – although probably a positive development if carried out wisely – now risks the shifting of accident and decommissioning costs from the plant owners to the general public because the relatively secure financial backing of substantial utility companies has in many cases been replaced by a limited liability subsidiary whose only asset is an individual nuclear power plant.

With years of reckless undermining of economic and financial regulation now exposed in a series of catastrophic financial collapses, investigators turning over rocks keep finding the same agents of decay: demands for short term "performance" in the private sector compounded by regulatory cutbacks, underqualified commission appointments, Congressional hearings harassing public protection initiatives, pressure to deregulate more and faster-a ruinous mixture of money, pressure, overconfidence, complexity and ideology.

During all those years, health and safety regulation got the same debilitating treatment from Congress and the Presidency as its financial counterparts. How long before those chickens come home to roost, and where will the roosting be?

Even in the best of times, regulation tends to be reactive, responding to events or to applications. Rarely does a regulatory commission develop a set of affirmative requirements to guide those who seek its permits. Certainly neither the Nuclear Regulatory Commission nor the several economic regulators with jurisdiction over nuclear plants ever developed a comprehensive policy to guide those seeking to transfer nuclear plant ownership. Such a policy might have required a showing that the protection of the public was in no way diminished by these transfers. Or such a requirement might have been imposed as a condition of approving the transfers.

- Commonwealth Edison experienced numerous simultaneous extended outages among the eight units at its Dresden, LaSalle, Quad Cities, and Zion nuclear stations. For example, during the first six months of 1996, the utility had at least three units shut down at any one time for extended outages of longer than three months in duration. Commonwealth Edison had at least four units shut down at any one time for extended outages during the last six months of 1996, except for a short period at the end of August and early September. The utility also experienced simultaneous outages of at least six months in length at its two unit Zion nuclear station from October 1993 through April 1994 and at its two unit LaSalle Station from September 1996 through 1998.
- Both units at the D.C. Cook Nuclear Plant in Michigan were shutdown from September 1997 through June 2000.
- Both units at the Salem Nuclear Station were shutdown for more than two years between July 1995 and August 1997.
- Both units at the Brunswick nuclear plant were shutdown for the twelve month period April 1992 through April 1993.
- Both units at the Calvert Cliffs nuclear plant were shut down at the same time for more than one year starting in May 1989.

Finding No. 2 - Complex, multi-tiered holding companies, often including limited liability subsidiaries, are increasingly being used to own nuclear power plants.

Except for those power plants owned by municipal utilities and the Yankee Nuclear Plants in the Northeast, nuclear units historically were directly owned by integrated investor-owned utility companies which owned other generating facilities and had significant transmission and distribution assets as well. Over the past five to ten years, however, corporations have established multiple tiered holding companies through which they indirectly own nuclear power plants. Except for the Exelon Corporation, these new nuclear power plant owning subsidiaries generally own only a single asset, i.e., an individual nuclear power plant, or both units at a multiple unit site.[6]

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[6] The nuclear industry's interest in single asset nuclear generating companies is not new. It dates back to the 1960s, perhaps even to the 1950s, when the plans were developed for the ownership of the Yankee Rowe and Connecticut Yankee nuclear plants. Then, in the late 1980s and early 1990s, some companies, including Middle South Utilities (subsequently renamed "Entergy") and General Public Utilities, reorganized, creating specific corporate entities to operate ***but not own*** their nuclear power plants. In one notable case in Michigan, however, the Consumers Power Company proposed transferring a poorly performing nuclear plant, Palisades, to a new corporate entity, PGCo, created for the sole purpose of owning and operating the plant. This ill-conceived proposal was designed to shift nuclear-related risks away from the Company, placing them instead upon consumers and the public. For more information, see Bruce Biewald, "Do We Really Need Nuclear Generating Companies?," in Public Utilities Fortnightly, June 7, 1990. and the Direct Testimony of Bruce Biewald, submitted on behalf of the Attorney General of Michigan, April 19, 1989 in Michigan Public Service Commission Case No. U-9172.

The corporate subsidiaries included in these complex ownership chains are increasingly chartered as Limited Liability Companies ("LLCs"). As we will discuss in Finding No. 3 below, LLCs are relatively new business structures that enhance a parent corporation's ability both to transfer funds from its nuclear-power plant owning subsidiaries and to shield its other assets from liability from the financial risks associated with its nuclear operations.

The following examples illustrate the accelerating trend in the nuclear industry to use multiple tiered holding companies and LLC subsidiaries to own and operate nuclear plants. It is important to note that each of the parent corporations listed in these examples also has numerous other subsidiaries unrelated to its nuclear power plant ownership.

Exelon Corporation

Exelon Corporation was formed in 2000 by the merger of Unicom (Commonwealth Edison Company's parent) and PECO Energy Company. Commonwealth Edison's 10 operating nuclear plants have been transferred to Exelon Generation Company, LLC, ("EGC") which is a wholly owned subsidiary of Exelon Ventures Company, LLC, which, in turn, is a wholly-owned subsidiary of Exelon Corporation. PECo's Limerick and Peach Bottom nuclear plants also have been transferred to EGC, as has PECo's ownership interest in the two Salem Nuclear Plants.

PECo also owned 50 percent of the AmerGen Energy Company, LLC, ("AmerGen") which had acquired and operated three nuclear power plants in the U.S.: Three Mile Island Unit 1, Clinton, and Oyster Creek. PECo's interests in AmerGen have been transferred to EGC, LLC. Consequently, through EGC, LLC, Exelon Corporation owns and operates part or all of 16 nuclear plants and owns part of another three units.

The current organizational structure through which Exelon owns these nuclear assets is illustrated in Attachment No. 1 to this Report.

Entergy

Entergy Corporation was a pioneer in establishing separate corporate entities to own and operate nuclear power plants. Entergy today owns and operates ten nuclear units through an extensive network of wholly-owned subsidiaries.

Entergy currently owns five nuclear units in the South through five wholly-owned retail public utility companies and another wholly-owned subsidiary, System Energy Resources, Inc.[7]

Entergy also has purchased another five nuclear units in the Northeast including its just completed purchase of the Vermont Yankee nuclear plant. As shown in Attachment No. 2 to this Report, Entergy owns each of these units through a multi-tiered series of subsidiaries, many of which are limited liability companies. For example, the Indian

[7] Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc.

Point 2, Indian Point 3, and Fitzpatrick nuclear units are each owned by a separate LLC.[8] In the case of Indian Point 2, the immediate owner is Entergy Nuclear IP2, LLC. This company is, in turn, owned by Entergy Nuclear Investment Company III, Inc., which is a wholly-owned subsidiary of Entergy Nuclear Holding Company #3 that, in turn is a wholly-owned subsidiary of Entergy Nuclear Holding Company. Entergy Nuclear Holding Company, Inc., is a direct subsidiary of Entergy Corporation.[9]

The structure through which Entergy owns the Indian Point 3 and Fitzpatrick units is even more complex because each of the LLCs that owns these plants is, in turn, 50 percent owned by two other indirect Entergy subsidiaries, Entergy Nuclear New York Investment Company I and Entergy Nuclear New York Investment Company II. As shown in Attachment No. 2, these two Entergy Nuclear New York Investment Companies are themselves subsidiaries of Entergy Nuclear Holding Company #1 which, in turn, is a wholly-owned subsidiary of Entergy Corporation.

Another Entergy subsidiary, Entergy Nuclear Operations, Inc. ("ENO") operates Entergy's nuclear units in the Northeast.[10] Additional services are provided by other Entergy subsidiaries such as Entergy Services, Inc. (management, administrative and support services) and Entergy Nuclear Fuels Company (nuclear fuel planning, procurement and related services).

Entergy has provided the following explanation for this tiered holding company structure:

> Entergy Nuclear Holding Company, a first tier of Entergy Corporation, has been established with the intent that it will ultimately hold all the subsidiaries associated with Entergy's nuclear operations. This will consolidate all of Entergy's unregulated nuclear operations under a single holding company, while still supporting the operational and financing demands of the individual plants. *The use of holding companies below Entergy Nuclear Holding Company allows Entergy to segregate various types of financing, investment and business activities, and by doing so, enables Entergy to better manage and control risks associated with these activities.*[11] (Emphasis added)

Remarkably, Entergy has indicated that only two of all of the subsidiaries included in Attachment 2 -- ENO and Entergy Nuclear Generation Company, which owns and operates the Pilgrim Nuclear Station -- have any employees other than officers.[12] The

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[8] Although the wholly-owned subsidiary that currently owns Entergy's Pilgrim Station is not an LLC, Entergy has said that it will seek to change the form of that subsidiary to an LLC in the near future.

[9] Entergy has said that ultimately all of subsidiaries associated with Entergy's nuclear operations will be owned by Entergy Nuclear Holding Company. Rebuttal Testimony of Connie Wells, Entergy Nuclear Vermont Yankee, LLC, in Vermont Public Service Board Docket No. 6545, at page 9.

[10] Entergy's nuclear units in the South are operated by yet another subsidiary, Entergy Operations, Inc.

[11] Rebuttal Testimony of Entergy Nuclear Vermont Yankee witness Connie Wells in Vermont Public Service Board Docket No. 6545, dated February 25, 2002, at page 9.

[12] Entergy response to Department of Public Service Information Request No. 2-10 in Vermont Public Service Board Docket No. 6545.

rest of the listed subsidiaries are merely paper organizations. In addition, the subsidiaries listed on Attachment 2 share many of the same individuals as officers.[13]

The NRC requires licensees of deregulated nuclear plants to provide certain financial guarantees that a unit would have sufficient funding to enable the licensee to continue to maintain the unit in a safe manner in case of an extended outage or a premature shutdown. Entergy's financial guarantees for its deregulated units in the Northeast are provided by two subsidiaries not listed in Attachment 2 -- Entergy International Holdings, LTD LLC and Entergy Global Investments, Inc. Both of these subsidiaries are themselves holding companies.[14]

As shown in Attachment No. 3, Entergy also has a very extensive network of other subsidiaries, in addition to those that own and operate its deregulated nuclear units in the Northeast.

Dominion

Dominion Resources, Inc. ("DRI") owns the two operating nuclear power plants at Millstone Point in Connecticut through a multi-tiered chain of subsidiaries. As shown on Attachment No. 4, DRI owns Dominion Energy Holdings, Inc. which, in turn, owns Dominion Energy Inc., LLC which owns Dominion Nuclear, Inc.. Dominion Nuclear, Inc. then owns Dominion Nuclear Marketing I, Inc, Dominion Marketing II, Inc, and Dominion Marketing III, LLC that together own Dominion Nuclear Connecticut, the direct owner of the Millstone nuclear station.[15]

Dominion also owns the four nuclear units at its North Anna and Surry stations in Virginia through the Dominion Generation Corporation which is a wholly-owned subsidiary of Dominion Energy Holdings, Inc. Dominion Generation Corporation also will own the fossil and hydro facilities that were formerly owned by Virginia Power Company.

Constellation

Constellation Energy Group, Inc. ("Constellation") purchased 100 percent of the Nine Mile Point Unit No. 1 nuclear plant and 82 percent of Nine Mile Point Unit No. 2 nuclear plant in 2001. Both of these units are located in upstate New York, near the City of Oswego. When Constellation sought NRC approval to transfer the units' licenses it also requested approval to complete a complex fourteen step corporate realignment. The nuclear-related results of this proposed realignment are shown on Attachment No. 5. The direct owner of the two Nine Mile Point nuclear plants is Nine Mile Point Nuclear Station, LLC, which is a wholly owned subsidiary of Constellation Nuclear Power Plants,

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[13] Synapse has learned greater detail about Entergy's current holding company structure through its involvement on behalf o the Vermont Department of Public Service in Vermont Public Service Board Docket No. 6545.

[14] Entergy response to Department of Public Service Information Request No. 1-42(c) in Vermont Public Service Board Docket No. 6545.

[15] Dominion's August 17, 2001 letter to the NRC concerning the Millstone Nuclear Power Station Corporate Restructuring.

Inc, which, in turn, is a wholly owned subsidiary of Constellation Nuclear, LLC. Constellation's other two nuclear plants are owned by another subsidiary of Constellation Nuclear Power Plants, Inc, Calvert Cliffs Nuclear Power Plant, LLC. Constellation also has numerous other nuclear-related subsidiaries. Constellation Nuclear, LLC is, in turn, a subsidiary of Constellation Energy Group, Inc.

The parent corporation resulting from this corporate realignment will be BGE Corporation which will own Constellation Energy Group, Inc., as an immediate subsidiary.

Other Companies

The owners of fleets of nuclear power plants are not the only corporations that have established multi-tiered holding companies to own their nuclear plants. For example, as part of its proposed reorganization to recover from bankruptcy, Pacific Gas & Electric is seeking permission to transfer its two Diablo Canyon Nuclear Plants to a new LLC subsidiary, Diablo Canyon LLC. As shown on Attachment No. 6, this subsidiary would, in turn be a wholly owned subsidiary of Electric Generation, LLC, which in turn is a subsidiary of the Newco Energy Corporation, a wholly owned subsidiary of PG&E Corporation.[16]

Another example is Public Service Enterprise Group ("PSEG") which owns and operates the Salem and Hope Creek nuclear plants and is part owner of the Peach Bottom Nuclear generation station through a line of wholly-owned subsidiaries that includes PSEG Power, LLC, and its wholly-owned subsidiary, PSEG Nuclear.

Finding No. 3 - Limited Liability Companies are relatively new business structures that are used to shield the assets of a parent corporation from liability for financial risks.

The fundamental purpose and rationale for the creation of a "corporation" is to allow investors to pool their resources to engage in a business activity while limiting the financial consequences or "liability" of each individual investor. The most typical arrangement is for an investor to purchase stock or "shares" in the corporation. The money or other value paid for the shares is the limit of that investor's personal liability. The corporation's total liability is limited to the value of its investors' shares, plus any insurance policies that may be applicable.

Partnerships, an alternative form of business organization, are characterized by the inability of the partners to limit their individual liability. Each partner is wholly and personally responsible for all debts of the business. This onerous feature of partnerships has led to the development of many variations on the partnership model, particularly the limited partnership, as a way to shield some or all of the partners from unlimited liability.

Looking only at the liability issue, one might wonder why partnerships are ever chosen as a business structure. There are two primary reasons: streamlined management and lower

[16] PG&E's November 30, 2001 Application to the NRC for License Transfers and Conforming Administrative License Amendments.

taxes. A corporation is required to have articles of incorporation, a board of directors, and a management structure separate from the board of directors. Partnerships can be much more flexible with the same individual, or group of individuals, performing both day-to-day management and decision-making functions. Tax policy significantly favors partnerships by allowing all business profits to flow directly to the partners where they are taxed on their business income along with any other personal income. Corporations, because they are considered a separate entity, must pay corporate taxes before profits can flow to its investors, who then pay taxes on their corporate income on an individual basis. This is commonly called the "double taxation" feature of corporations.[17]

The dilemma facing entrepreneurs who want to start a business is whether the business structure should be designed to protect their existing personal assets by limiting their liability (a corporation) or whether the business structure should be designed to allow them to maximize their income from this single venture through lower taxes (a partnership). As discussed below, the nuclear industry seeks to achieve both liability protection and maximum income through the use of new limited liability corporate structures.

Limited Liability Subsidiaries

Limited liability companies (LLCs) are relatively new business structures that combine features of corporations and partnerships. An LLC has the same limited liability of corporations, but has the management flexibility of a partnership. Most significantly, pursuant to an IRS ruling in 1988, an LLC is considered a partnership for federal income tax purposes.

The first LLCs in the United States were formed in Wyoming in 1977 for foreign corporations that wanted to invest in very risky mineral exploration and development. Since 1977, LLC statutes have been enacted in all fifty states. They have proven to be a particularly attractive business structure for investments in high-risk ventures. LLCs can be formed by individuals, partnerships, or corporations. They can be managed by the LLC members (owners) or by an elected group of members, or by a single member. The management choice also acts to specify the members who can legally bind the LLC through contracts with outside entities.[18]

LLCs have become a very attractive business structure for corporations that acquire nuclear power plants. By creating a separate LLC for each nuclear plant, the profits from each plant's operations can flow back to the parent corporation without any intervening tax liability. The parent corporation's liability for each plant is limited to the investment the parent corporation made in initially setting up the LLC. Also, there can be more than one LLC between the parent corporation and the most risky component of the overall

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[17] For general background on business structures, see any of a number of law school texts on business organizations. The information above is derived from "Organizing Limited Liability Companies: The Trend Continues", Richard M. Fijolek, Practicing Law Institute (1997); "A Limited Liability Company Checklist", Jerome P. Friedlander, II, Federal Lawyer (March/April 1995); and "The ABCs of LLCs, Steven Auderieth, Vermont Bar Journal and Law Digest (February, 1995).

[18] See above, Friedlander and Auderieth.

investment. For example, the technical support services for several nuclear plants can be consolidated into a separate LLC that contracts with all the individual plant LLCs. If one nuclear plant becomes unprofitable and goes into bankruptcy proceedings, in theory, only the single plant LLC assets are in jeopardy; the technical services LLC can continue to provide services to all the other single plant LLCs.

A particular concern regarding the use of LLCs is the situation where a parent corporation inserts several layers of LLCs between itself and the entity operating a high-risk business. Each of those intervening LLCs can act as a barrier to extending liability to the parent corporation that contains most of the assets. As noted in the case studies in Finding No. 2 of this Report, this approach appears to have been embraced by the parent corporations that recently have been purchasing nuclear plants. If a nuclear plant was unable to cover its liabilities, it might require several separate litigations, or a very large and complex single litigation, to pierce all the corporate veils back to the parent corporation with the bulk of the assets.

Finding No. 4 –There continue to be significant financial and other risks associated with nuclear power plant ownership and operations.

The restructuring of electricity markets has meant increased risks for owners of any deregulated electric generation facilities, whether their plants are fossil-fired or nuclear. Revenues which used to be based on traditional "cost of service" concepts and stable rates are now based instead on the actual sales from a power plant at market prices that are sometimes volatile.

At the same time, there are significant nuclear-related risks that could have a material adverse effect on nuclear power plant owners. For example, a recent Prospectus issued by Exelon Corporation for the sale of $700 million of notes by Exelon Generation Company, LLC specifically identified the following risks associated with owning and operating nuclear power plants:

> We may incur substantial cost and liabilities due to our ownership and operation of nuclear facilities. The ownership and operation of nuclear facilities involve certain risks. These risks include: mechanical or structural problems; inadequacy or lapses in maintenance protocols; the impairment of reactor operation and safety systems due to human error; the costs of storage, handling and disposal of nuclear materials; limitations on the amounts and types of insurance coverage commercially available; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. The following are among the more significant of these risks:
>
> Operational risk. Operations at any nuclear generation plant could degrade to the point where we have to shut down the plant. If this were to happen, the process of identifying and correcting the causes of the operational downgrade to return the plant to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet our supply commitments. For plants operated by us but not wholly

owned by us, we could also incur liability to the co-owners. We may choose to close a plant rather than incur substantial costs to restart the plant.

Regulatory risk. The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under it or the terms of the licenses of nuclear facilities. Changes in regulations by the NRC that require a substantial increase in capital expenditures or that result in increased operating or decommissioning costs could adversely affect our results of operations or financial condition.

Nuclear accident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and elsewhere. The consequences of an accident can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident could exceed our resources, including insurance coverages.

These same risks apply to other nuclear plants including those owned and operated by multi-tiered holding companies and LLCs.

The industry's expressed desire to build new nuclear plants also can be expected to increase the financial pressures on licensees as they may have to further reduce O&M expenditures at existing plants in order to fund the construction of new ones.

Finding No. 5 - The NRC has expressed concern that deregulation can adversely affect the safety of operating nuclear power plants by increasing the pressure on licensees to reduce costs.

Although it has been said that an efficient and economical plant is often a safe plant,[19] the NRC has expressed concern that the transition to economic deregulation can adversely affect nuclear power plant safety and may not provide the same degree of assurance that adequate funds would be provided for safe operation and decommissioning.[20]

The NRC has further explained the impact that increased competition can have on nuclear power plant economics and safety:

> As described in SECY-97-253, traditional "cost-of-service" regulation, under which virtually all NRC power reactor licensees have operated, has typically been effective in providing necessary funds for licensees to operate and decommission their nuclear plants safely. With the advent of greater competition within the electric utility industry, pressures to reduce costs and improve efficiency have increased and will almost certainly intensify as deregulation proceeds. Moreover, with deregulation of the generation sector of the industry, traditional cost-of-service regulation is likely to essentially disappear for most generators. Thus, the concept of electric utility, as

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[19] *NRC Staff Requirements Memorandum, SECY-98-153*, dated June 29, 1998, at page 3.

[20] *NRC Final Policy Statement on the Restructuring and Economic Deregulation of the Electric Utility Industry* (62 *Fed. Reg.* 44071; August 19, 1997)

currently defined in 10 CFR 50.2 may in the future no longer be meaningful for a large number of, if not all, power reactor licensees. Electricity rates set by competition in a free market may not provide the same degree of assurance of adequate funds for safe operation and decommissioning as traditional cost-of-service ratemaking. In SECY-97-253, the staff cited the example of the "Independent Safety Assessment of Maine Yankee Atomic Power Company" (NRC Staff Report: Ellis W. Merschoff, Team Lead; October 1996), which concluded, "Economic pressure to be a low-cost energy producer has limited available resources to address corrective actions and some plant improvement upgrades.

When the NRC issued its Final Policy Statement on the Restructuring and Economic Deregulation of the Electric Utility Industry (62 *Fed. Reg.* 44071; August 19, 1997), specific safety concerns with respect to rate deregulation and restructuring were identified. For example, the final policy statement discussed such safety concerns as reductions in expenditures for manpower and training and other reductions in operations and maintenance (O&M) and capital additions budgets. The issues of on-line maintenance and increased fuel burnup were also addressed.

In addition, with respect to specific plants such as Maine Yankee, Millstone, and others, the inspection process has identified several manifestations of inappropriate responses to competitive pressures. These include: increased need for corrective actions; maintenance operator work-arounds; temporary modification and procedure revision backlogs; decreased performance in operator licensing and requalification programs; increased frequency of significant operational and occupational safety events; decreased plant and system reliability; increased volume and acrimony of allegations; and increased frequency of regulatory violations and resulting penalties.

As deregulation proceeds, cost pressures may increase these types of reductions in safety margins at plants. Moreover, because the impact of budgetary reductions can cut across all plant safety-related programs, other impacts in addition to those previously identified may occur as a result of deregulation. For example a merchant plant with no assets other than the nuclear plant itself could be unable to make necessary safety expenditures after an extended outage if it did not have an adequate financial cushion to pay costs incurred during the outage. In such a situation, it is not clear that a transition from indefinite shutdown to permanent shutdown and decommissioning would be sufficiently smooth to prevent funding shortages from causing safety problems during the shutdown transition period. That is, given the requirements in 10 CFR 50.82 with respect to: (1) the limitation on the use of the trust fund for legitimate decommissioning activities; and (2) the timing of significant decommissioning trust fund withdrawals, a licensee could run out of funds for operational safety expenses before it was able to draw on its decommissioning trust fund. This, in turn, could force the NRC to

make the decision for the licensee to permanently cease operations and initiate decommissioning pursuant to 10 CFR 50.82.[21]

The nuclear industry itself has acknowledged the safety and economic risks associated with economic deregulation. For example, a former President of the industry's American Nuclear Society told the Society's Winter 2001 meeting that "Safety is the highest priority because of the impact on cost that would result from an NRC-forced shutdown" and that there is now "actually a higher focus on safety than before."[22] However, he also noted the challenges that come from deregulation and restructuring:

> With restructuring comes challenges for plant operators and regulators, Quinn continued. These challenges for operators include management focus on economics, not safety; pressure on workers to keep plants operating (because of volatility of electricity prices); pressure to reduce preventative maintenance; deferral of equipment replacements; and less investment for safety backfits. For the regulator, these include increased workload (because of mergers, license transfers, etc.); pressure to avoid requiring shutdowns of plants; and increased political pressure to reduce the regulatory burden. Challenged also is the nuclear technology infrastructure. According to Quinn, there is less cooperation among competing nuclear utilities, and less safety research and technical support for the plants.[23]

Finding No. 6 - The NRC has expressed concern that the use of holding company structures can reduce the assets that would be available for the safe operation and decommissioning of a nuclear power plant. However, the NRC does not adequately protect against the risk that an LLC subsidiary will transfer all of its operating profits to its parent company or engage in risky loans to or questionable deals with affiliates.

The NRC Staff has expressed concern that the use of holding company structures can lead to a diminution of the assets necessary for the safe operation and decommissioning of a licensee's nuclear power plant.[24] In fact, as early as March 1993 the NRC Staff expressed concern that:

> Current and potential organizational structures of many power reactor licensees and their corporate affiliates are complex and evolving. The staff believes that the public health and safety implications of such structures warrant further examination. A licensee subsidiary without assets other than

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[21] *NRC Staff Requirements Memorandum, SECY-98-153*, dated June 29, 1998, at pages 2 and 3.

[22] *ANS Winter Meetings: Nuclear Power - Attracting Notice, A Brighter Outlook*, Nuclear News, August 2001, starting at page 34.

[23] Ibid.

[24] *Safety Evaluation by the NRC's Office of Nuclear Reactor Regulation "Related to Proposed Corporate Restructuring of Commonwealth Edison Company,"* October 5, 2000, at page 3.

> the licensed reactor could renege on its decommissioning obligations if forced to shut down prematurely. Given that corporate law generally limits the liability of stockholders, the NRC may not have recourse to the assets of a parent company if its subsidiary defaults absent legally enforceable commitments by owners. Case law with respect to bankruptcy proceedings is also ambiguous. Although bankruptcy courts have generally directed bankruptcy trustees to make justifiable, legally required expenditures to protect public health and safety, it is not clear that these expenditures will always have a high priority relative to other claims. The staff believes that it should evaluate possible ways to increase assurance of decommissioning funds availability. An increased degree of confidence may be appropriate to assure that the problems that the Office of Nuclear Material Safety and Safeguards has had with some of its licensees abandoning materials sites prior to cleanup will not be experienced for power reactor licensees.[25]

The NRC Staff consequently requested that the NRC Commissioners approve publication of an advance notice of proposed rulemaking to explore alternatives to mitigate the potential impact on safety of power reactor licensee ownership arrangements and to consider whether increase assurance of funding availability for decommissioning activities was needed.

> *A licensee subsidiary without assets other than the licensed reactor could renege on its decommissioning obligations if forced to shut down prematurely.*
>
> NRC Staff, March 1993

Unfortunately, the NRC Commissioners disapproved this request and, instead, asked for additional information on the staff proposal. In response to a Commission question on how many reactor licensees could try to set up a corporate veil to avoid decommissioning costs, the NRC Staff noted:

> Potentially, any investor-owned utility could establish a holding company to which it could transfer the bulk of its assets over time. If forced to shut down prematurely, a licensee with assets limited essentially to the shut down reactor could declare bankruptcy and renege on any unfunded decommissioning obligation. If a bankrupt licensee had insufficient assets, a bankruptcy court might be powerless to order that assets of a parent company be used to fund decommissioning, even if the court wished to do so.[26]

In the years since 1994, the NRC has not developed or adopted any policy limiting the transfer of operating profits from the subsidiary that directly owns a nuclear plant. Nor

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[25] *Issuance of An Advance Notice of Proposed Rulemaking on the Potential Impact on Safety of Power Reactor Licensee Ownership Arrangements, SECY-93-075,* March 24, 1993, at page 1.

[26] *Response to Staff Requirements Memorandum of April 28, 1993, Which Disapproved Issuance of An Advance Notice of Proposed Rulemaking on the Potential Impact on Safety of Power Reactor Licensee Ownership Arrangements, SECY-94-280,* at pages 4 and 5

does the NRC have any policy limiting the types or magnitudes of the loans that such an operating subsidiary can make to affiliated companies.

At most, the NRC merely conditions license transfer approvals to new holding company structures upon a requirement that the licensee not transfer to its proposed parent or any other affiliated company significant assets for the production, transmission or distribution of electric energy without first notifying the NRC. The NRC has defined "significant assets" to be facilities having a "depreciated book value exceeding 10% of the company's consolidated net utility plant."[27]

The NRC also does not have a specific policy statement or procedure on how limited liability companies or other types of licensees use financial assurance funds in the forms of lines of credit for plant operation.[28] Nor does the NRC have any specific policy statement or procedure that controls how it would consider approval of requests of limited liability companies to reduce, replace, or withdraw available lines of credit that are subject to NRC conditions. Instead, the NRC has said that it will review such requests on a case-by-case basis.[29]

The NRC has explained its policy for addressing situations where a licensee has drawn upon the lines of credit provided by a parent or affiliated companies. In such situations, the NRC would:

> evaluate the reasons behind [the licensee's] drawing on the lines of credit. The staff cannot provide a detailed discussion of potential agency actions until it learns the specific reasons for the usage of such funds. Generally, if drawings on the lines of credit were made to cover short-term cash flow deficiencies that did not appear to have any significant safety ramifications, the NRC would not likely need to take any specific action. If drawing on the lines of credit were to indicate serious longer-term financial problems that appeared to potentially adversely impact protection of public health and safety, the NRC would monitor the effects of any degradation on protection of public health and safety and act appropriately.[30]

The NRC's failure to have any policy limiting the transfer of operating profits from the subsidiary that directly owns a nuclear plant or the types or magnitudes of the loans that such an operating subsidiary can make to affiliated companies is all the more significant because the new holding companies also may have not set policies governing these matters. For example, Entergy has said that there are no written procedures governing the distribution of operating profits from the subsidiaries that are the direct owners of its

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[27] For example, see the October 5, 2000 Safety Evaluation by the NRC Office of Nuclear Reactor Regulation of the proposed corporate restructuring of PECO Energy Company, at page 3.

[28] Enclosure 1 to the NRC's December 13, 2001 letter to Christine Salembier, Commissioner, Vermont Department of Public Service, on the subject of "Vermont Yankee Nuclear Power Station – Lines of Credit Associated with Vermont Yankee License Transfer."

[29] Ibid.

[30] Ibid.

nuclear units.[31] These subsidiaries either make distributions to their immediate parent companies or make loans to affiliated companies depending on the specific cash requirements of the parent companies or the affiliates.

Vermont Department of Public Service witness Andrea Crane has explained to the Vermont Public Service Board why it should be concerned about the ability of a parent corporation to drain the funds available to a nuclear power plant-owning subsidiary:

> ...in addition to being concerned about the availability of capital for ENVY's[32] operations, there is also a concern that Entergy Corp. may threaten the long-term financial viability of ENVY by using ENVY's earnings to fund other Entergy Corp. operations, leaving insufficient funds in ENVY for nuclear operations. Therefore, in addition to raising concerns about the availability of sufficient operating and capital funds, I am also concerned about the need to retain capital in ENVY. The Board should avoid a repeat of the situation that transpired in PG and E ... whereby funds were transferred from a successful operating entity to the holding company, leaving the operating company in dire financial straits.[33]

Ms. Crane also expressed concern about the absence of formal Entergy corporate policies governing the transfer of profits and inter-affiliate transactions:

> The lack of direct control over its internally generated funds, and the vagueness of the corporate policy, does not provide an appropriate level of financial assurance for the ownership and operation of a nuclear power plant. It leaves open the possibility that Entergy Corp could require 100% of operating earnings as dividends from its subsidiaries, including ENVY, if it needed funds to meet other priorities or emergencies, leaving the owners of the nuclear plants without sufficient capital to pursue their own immediate priorities.[34]

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[31] Entergy Response to Department of Public Service Information Request No. 2-36 in Vermont Public Service Board Docket No. 6545.

[32] ENVY is Entergy Nuclear Vermont Yankee LLC, which is the Entergy Corporation subsidiary that will own the Vermont Yankee nuclear plant if the purchase is approved by the Vermont Public Service Board.

[33] Direct Testimony of Andrea Crane on behalf of the Vermont Department of Public Service, Vermont Public Service Board Docket No. 6545, at page 9.

[34] Direct Testimony of Andrea Crane on behalf of the Vermont Department of Public Service, Vermont Public Service Board Docket No. 6545, at page 28.

Finding No. 7 - The NRC's reviews of the financial qualifications of new nuclear power plant owners are inconsistent and may be too limited to ensure that subsidiaries will have adequate funds to safely operate and decommission their nuclear plants and pay retrospective Price-Anderson Act premiums.

Before it allows a nuclear power plant operating license to be transferred, the NRC conducts reviews of the financial qualifications of the prospective owner. The NRC's regulations specify the types of information that a prospective licensee must provide and the nature of the review that must be conducted by the NRC staff.

However, the applicable NRC regulation, 10 CFR 50.33(f), is inconsistent in that on the one hand it says that "the applicant shall submit information that demonstrates the applicant possesses or has reasonable assurance of obtaining the funds necessary to cover estimated operation costs for the **period of the license**." (emphasis added) But the regulation then merely requires applicants to submit estimates for total annual operating costs for only the first 5 years of operation of the facility. Although the NRC can ask for information for subsequent years, this regulation can mean that the NRC will only review five years of operating cost data when the new owner may be seeking transfer of a license which will continue in effect for another 25 years or longer.

In reviewing the financial qualifications of a prospective licensee, the NRC requires that the new owner either meet a supply and demand test or show that it has an investment grade rating or equivalent from at least two bond-rating organizations. The supply and demand test examines whether the prospective licensee will earn sufficient revenues (either from the sale of electric power from the nuclear plant or from other sources) to cover expected operational expenses at the plant.[35] This analysis is based on the applicant's uncertain and speculative estimates of total operating revenues and costs for the first full five years following the expected completion of the license transfer.[36] At the same time, it is very unlikely that the new corporate subsidiaries that actually will own the transferred plant will have issued any securities that had received investment grade or equivalent ratings from any bond-rating organizations.

If a prospective licensee is unable to meet either the supply and demand test and or the bond rating criteria test, the NRC will consider its ability to fund a six-month outage. Although assuring the funding for a six-month outage is not required where a prospective licensee meets either of the NRC's two primary tests, in those cases where a prospective licensee voluntarily guarantees the funds to pay for a six-month outage, the Commission will accept that commitment and impose a licensee condition prohibiting the applicant from voiding or diminishing those guarantees.

The U.S. General Accounting Office ("GAO") has evaluated the NRC's review of the financial qualifications of prospective licensees to safely operate and decommission

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[35] NUREG-1577, Revision 1, at Section III.1.b.

[36] It also appears that the NRC does not consider the need to pay retrospective Price-Anderson Act premiums when it considers a prospective licensee's financial qualifications to safely operate and decommission a nuclear power plant.

nuclear power plants. The GAO concluded that for the most part, the NRC's reviews of new owners financial qualifications have enhanced the level of assurance that they will safely own and operate their plants in a deregulated environment and not need to shut them down prematurely.[37]

However, the GAO also found that the NRC did not always adequately verify the new owners' financial qualifications.[38] In particular, the GAO concluded that when the NRC reviewed the financial qualifications of Exelon to safely own and operate the largest fleet of nuclear plants in the U.S., it did not require the same additional guarantees from the parent or affiliated companies that the new owner would have sufficient revenues to cover the plants' operating costs as it had required from other proposed license transfers.[39] The NRC also did not validate the information submitted by the new owner to demonstrate that the company was financially qualified.[40] In fact, the GAO concluded that the NRC had eventually transferred the licensees to Exelon Generation Company on the basis of projected financial information that both the affected companies and the NRC knew to be inaccurate.[41]

The NRC's review of financial qualifications continues after a license is transferred. Each licensee is required to submit an annual financial report, pursuant to 10 CFR 50.71(b) and a decommissioning funding status report is required every two years.[42] The NRC Staff also monitors the general financial status of nuclear plant licensees by screening the trade and financial press reports, and other sources of information.[43]

However, it is unclear whether the NRC has the staff resources or the expertise to conduct adequate reviews of licensee's financial qualifications. For example, the NRC's Executive Director for Operations informed the Commissioners in April 1997 that the expertise of the NRC Staff in matters of finance and economic analysis were "limited."[44] At the same time, the size of the NRC Staff has been reduced by approximately ten percent since 1997.[45]

The NRC has expressed confidence in its Staff's ability to identify financial distress and has quoted approvingly a Staff member who said "severe financial distress from any of the licensees is something that's not going to be hidden from view very long."[46] However, the suddenness of ENRON's collapse and the apparent absence of public warnings of that

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37 *Nuclear Regulation: NRC's Assurances of Decommissioning Funding During Utility Restructuring Could be Improved*, GAO-02-48, December 2001, at page 6.

38 Ibid., at page 4.

39 Ibid., at page 21.

40 Ibid., at pages 21 and 31-32.

41 Ibid., at page 33.

42 10 CFR50.75(f)(1).

43 NUREG-1577, Rev 1, Section III.1.d., at page 5.

44 NRC SECY-97-071, April 2, 1997.

45 NUREG-1350, Vol. 13, Figure 4.

46 *In the Matter of Power Authority of the State of New York and Energy Nuclear Fitzpatrick*, 53 N.R.C. 488, June 21, 2001.

company's severe financial distress prior to that collapse suggest that the NRC may not have any warning about a licensee's impending financial problems.

Finally, the NRC recently has indicated its intention to reduce the regulatory burden on licensees by eliminating the requirement that licensees include financial qualifications information in license renewal applications.[47] This would mean that there would be no assessment of the financial qualifications of a licensee to safely operate a nuclear power plant for up to an additional twenty years beyond the expiration of its existing NRC-issued license.

In conclusion, there are a number of reasons to have serious concerns about the quality of the NRC's review of the financial qualifications of licensees and prospective licensees.

Finding No. 8 - The financial guarantees that the NRC requires from prospective nuclear power plant owners may not be adequate to assure that plants are operated and decommissioned safely and that plant owners will be able to pay deferred Price-Anderson Act insurance premiums in the event of a nuclear accident.

The NRC has generally accepted guarantees from prospective nuclear power plant licensees in the range of $55 to $75 million to pay for a six-month outage. However, in a number of cases the licensee has not offered and the NRC has not required the licensee to make any such guarantee.[48] For example, there appears to be guarantees in place for only three of the nuclear units owned by Exelon Generation Company, LLC. These are the three units that were originally 50 percent owned by PECO Energy Company and were transferred to Exelon Generation Company, LLC as part of the merger between Unicom and PECO Energy. The guarantees that were in place when the plants were owned by PECO Energy and British Energy were transferred along with the plants. However, it does not appear that there is any guarantee in place for the other 16 nuclear plants that are currently owned by Exelon Generation, Company, LLC.

There is no evidence that these limited $55 to $75 million guarantees will provide sufficient funds to enable power plant owners to safely shutdown their nuclear plants in case of a serious event or significant problem and to maintain the plant in a safe shutdown condition until the problem is addressed or the licensee is able to gain access to the plant's decommissioning trust fund. For example, a substantial number of nuclear power plants have been shutdown since January 1996 for outages that lasted far longer than six months:

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[47] FedNet Government News, June 5, 2002.

[48] As we will discuss in Finding No. 9, Constellation has guaranteed that its nuclear power plant-owning subsidiaries, Nine Mile Point LLC and Calvert Cliffs Nuclear Plant LLC will receive whatever cash is needed to protect the public health and safety.

Table No. 2
Nuclear Power Plant Outages
Since June 1995
That Lasted Nine Months or Longer

Plant	Period Shutdown	Outage Duration
Beaver Valley 2	December 1997 - September 1998	9 months
Clinton	September 1996 - May 1999	32 months
Cook Unit 1	September 1997 - December 2000	39 months
Cook Unit 2	September 1997 - June 2000	33 months
Indian Point 2	February 2000 - December 2000	10 months
Kewaunee	September 1996 - June 1997	9 months
LaSalle Unit 1	September 1996 - August 1998	23 months
LaSalle Unit 2	September 1996 - April 1999	31 months
Millstone Unit 2	February 1996 - May 1999	39 months
Millstone Unit 3	March 1996 - June 1998	27 months
Point Beach Unit 1	February 1997 - December 1997	10 months
Point Beach Unit 2	October 1996 - August 1997	10 months
Salem Unit 1	May 1995 - April 1998	35 months
Salem Unit 2	June 1995 - August 1997	26 months

Indeed, as Table No. 1 (in Finding No. 1 above) and Table No. 2 reveal, it is not unusual for more than one unit at a single site to be shutdown for an extended outage at the same time. These simultaneous extended outages could significantly increase the financial pressures on the units' owner in a deregulated environment when its cash flow depends on the actual sales from the plant rather than on regulated rates for an entire utility.

Moreover, it is not unreasonable to expect that a nuclear unit might be shutdown for more than six months before the ultimate parent corporation makes the decision to permanently retire the unit. After all, the full extent of the plant's problems and the expense and time it would take to repair and restart the unit might not be apparent until the plant had been shut down for a substantial period of time.

This could mean that all of the funds guaranteed by an affiliate or the parent corporation could be exhausted before the licensee would be able to gain access to the unit's decommissioning fund. For example, Millstone Unit 1 was shutdown for 31 months before Northeast Utilities decided in July 1998 to permanently retire the plant. Commonwealth Edison Company's Zion Units 1 and 2 were shutdown for eleven and sixteen months, respectively, before the Company decided in January 1998 to

permanently retire both plants. The Maine Yankee plant was shut down for eight months before its Board of Directors decided in August 1997 to permanently retire it.

But even if an outage were shorter than six months, the maintenance and/or capital expenditures required to repair a plant and restore it to service may be significantly higher than the company had projected in its application to the NRC. The limited funds pledged by a parent corporation or an affiliate could be inadequate under such circumstances.

Finding No. 9 – The NRC has proposed to significantly reduce its review of a non-electric utility licensee's financial qualifications when it evaluates an application to renew a nuclear plant's operating license.

The NRC has proposed to eliminate the requirement that non-electric utility power reactor licensees submit financial qualifications information in their license renewal applications.[49] At the same time, the NRC also has proposed to require the submission of such information when utilities reorganize and operate as "non utility" generators.

The NRC's proposal to require financial reviews when a utility recognizes with a new financial structure is important. However, the decision to reduce disclosure obligations on nuclear power plant owners when they seek renewal of operating licenses for up to 20 years creates the potential for added risk of non-performance in critical areas.

A formal and rigorous review at the time of license renewal for aging nuclear reactors is a particularly appropriate time to evaluate the financial requirements. It is at this point that a business plan can be evaluated over the proposed lifetime of a licensee's facility. The financial resources needed to address the safe and secure operations, make capital improvements to a complex 30 year old machine, meet added license conditions required after the events of September 11, 2001, and to meet decommissioning and public liability obligations under the Price Anderson Act, must be juxtaposed against the economic conditions in the electricity markets and the availability of capital and insurance.[50]

The NRC's justification for not requiring a financial qualifications review at the time of relicensing is that it can monitor licensees when changes take place in licensee's financial qualifications. These day-to-day or limited annual reviews are not substitutes for a

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[49] June 4, 2002 Federal Register, at Vol. 67, No. 104, pp. 38427.

[50] The wisdom of looking into the future was underscored in the case of USEC, Inc, which has an NRC Certificate under 10 CFR Part 76 to operate uranium enrichment plants. The NRC conducted a financial review of the USEC, Inc. Certificate when it was issued in 1998 using the threshold of a current investment grade credit rating. The NRC determined USEC was reliable and economic based on its BBB+ investment grade debt rating. However, the NRC did not look beyond the 5 year term of the certificate to evaluate USEC's financial qualifications or the company's ability to operate with an unsustainable business model. If it had, it could have readily foreseen that USEC's financial condition would deteriorate over time due to a number of factors including the declining value of its sales contract, lower market prices, increasing unit costs of output and lack of competitive technology to enrich uranium for nuclear power reactors. These factors led to multiple credit downgrades and subsequent NRC doubts about whether USEC's economic resources were sufficient to be recertified for another 5 years.

formal, rigorous and disciplined review examining all a licensee's financial ability to fulfill its obligations for safely and securely operating an aging reactor in a competitive marketplace.

Historically, the ratemaking process for a utility corporation had provided reasonable assurance that a license applicant would have funds necessary to operate a reactor. In these circumstances, a licensee could be assumed of obtaining all of the reasonable funds it needed to continue operating its aging power plant. However, non-utility generators now lack the same assured funding, and as utilities diversify into telecommunications, trading operations and high-risk financial activities, the risk that there will be insufficient capital grows. To provide a green light for 20 years of operation without a rigorous review of a licensee's financial resources and business plans invites unwelcome surprises.

Finding No. 10 - The NRC does not require that parent corporations guarantee that funds will be provided to safely operate and decommission the nuclear power plants owned by their subsidiary companies.

The NRC does not require that a parent corporation guarantee the funds that may be needed to operate and decommission safely the nuclear power plants owned by subsidiaries. Instead, the NRC Staff has included conditions requiring a parent guarantee in the orders approving license transfers as additional assurance of financial qualifications only when such a guarantee has been offered by the applicant.[51].

For example, in its reviews of the financial qualifications of Entergy Corporation to own the Pilgrim, Indian Point 2, Indian Point 3, Fitzpatrick, and Vermont Yankee nuclear plants, the NRC has accepted guarantees that would be provided through lines of credit from affiliated financial subsidiaries which may not have sufficient liquid capital when it is needed by a plant-owning affiliate. One of these credit lines is to be used for working capital, if needed. The other is not intended to be used in the normal course of business but instead would be used in the event of problems at the plant. Entergy has indicated that this line of credit would be used to pay the costs between the unplanned shutdown of a plant and the availability of funds from the plant's decommissioning trust fund.[52]

Vermont Department of Public Service witness Andrea Crane has explained the problems that can arise from the fact that neither of the Entergy subsidiaries that provide these lines of credit have any physical assets:

> The result is that these two companies are only as strong as 1) their receivables from, and investment in, associated companies, and 2) Entergy Corp's commitment to provide them with additional funds, if required. Entergy Corp, therefore, has full discretion as to whether or not to provide sufficient capital to EIHL and EGI so that these two financing vehicles can

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[51] *In the Matter of GPU Nuclear, Inc and AmerGen Energy Company, LLC*, 51 N.R.C. 193, at Footnote No. 8.

[52] Prefiled Direct Testimony of Michael R. Kansler, Entergy Nuclear Vermont Yankee, Vermont Public Service Board Docket No. 6545, at page 10.

> meet their commitments to ENVY. If Entergy Corp should choose to walk away from EIHL and EGI, there appears to be no recourse for ENVY.[53]

For this reason, Ms. Crane recommended that the parent Entergy Corporation be required to guarantee that the pledged funds actually would be available if needed:

> Entergy Corporation should be obligated to stand behind the total financial exposure occasioned by the ownership and operation of this nuclear power plant. It is not reasonable to allow Entergy Corporation to shield itself from financial responsibility with complex financial arrangements. It certainly should not be allowed to offer guarantees from subsidiaries that do not have sufficient assets to meet their obligations on a stand-alone basis, because the parent could walk away from those subsidiaries if its own interests so dictated. If Entergy Corporation intends to stand behind the guarantees of its subsidiaries, it should have no problem in making the guarantee directly.[54]

Even though the NRC had accepted the $70 million guarantee provided by the two lines of credit from Entergy Corporation subsidiaries, in response to the concerns raised by the Ms. Crane and the Vermont Public Service Board, the parent Entergy Corporation has provided an additional financial guarantee of up to $60 million.[55] As Entergy has explained:

> The intent of that guarantee is to make sure that, in the event of a premature shutdown of the Vermont Yankee Nuclear Power Station, there will be money available to bridge the gap between shutdown and the point at which ENVY is able to access the decommissioning trust fund. Thus, if either line of credit has been drawn upon, Entergy will guarantee to make up any deficiency up to a total of $60 million.[56]

Entergy also acknowledged that the parent corporation has not provided a similar guarantee in support of **any** of the other nuclear plants its subsidiaries have acquired.[57] It further noted that state and federal regulators, including the NRC, had found the smaller guarantees by affiliated companies, not the parent corporation, to be sufficient.[58]

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[53] Direct Testimony of Andrea Crane on behalf of the Vermont Department of Public Service, Vermont Public Service Board Docket No. 6545, at page 18.

[54] Direct Testimony of Andrea Crane on behalf of the Vermont Department of Public Service, Vermont Public Service Board Docket No. 6545, at page 22.

[55] Ms. Crane subsequently testified that the revised commitments by the parent Entergy Corporation adequately addressed the concerns in her Direct Testimony. Supplemental Testimony of Andrea Crane in Support of the Memorandum of Understanding in Docket No. 6545, at page 2 of 9.

[56] Rebuttal Testimony of Connie Wells, Entergy Nuclear Vermont Yankee, LLC, in Vermont Public Service Board Docket No. 6545, at page 3, lines 8-13.

[57] Ibid., at page 5, lines 1-5.

[58] Ibid.

Dominion has voluntarily committed $150 million from the parent corporation, DRI, to assure that Dominion Nuclear Connecticut (the new owner of the Millstone Nuclear Station) will have sufficient funds available for meeting its operating expenses for the recently acquired Millstone Units 2 and 3.[59] Dominion has explained that the subsidiary, Dominion Nuclear Connecticut, has the right to obtain such needed funds from DRI as it determines "are necessary to protect the public health and safety, meet NRC requirements, meeting ongoing operational expenses or to maintain Units 2 and 3 safely."[60] However, it does not appear that Dominion has made the same commitment to the four nuclear plants at the Surry and North Anna sites owned by the Dominion Generation Corporation.

Constellation has guaranteed that each of its nuclear power plant-owning subsidiaries, i.e., Nine Mile Point Nuclear Station LLC and Calvert Cliffs Nuclear Plant LLC, would be provided whatever cash is needed to protect the public health and safety.[61]

But it does not appear that the parent Exelon Corporation has guaranteed any funds to its power plant owning and operating subsidiary Exelon Generation Company, LLC.

Finding No. 11 – Taxpayers may be at risk if nuclear plant owning subsidiaries are unable to continue making safety-related or decommissioning expenditures or pay retrospective Price-Anderson Act premiums.

In attempting to assure the Vermont Public Service Board that the former owners of the Vermont Yankee nuclear plant and their ratepayers are unlikely to be required to pay any shortfalls in decommissioning funds, Entergy has noted that the NRC has on several occasions said that the burden of paying any such shortfalls would fall on taxpayers:

> NRC regulations do not specifically address the potential liability of other parties in the event that the licensed owner is unable to provide the funds required for decommissioning. In the past, the NRC indicated that any failure of the licensed owner to meet its decommissioning funding obligations would result in a burden on taxpayers -- presumably in the form of a publicly funded cleanup. See, e.g., SECY-94-280 (Nov. 18, 1984), at 4. ("Such action would either increase the potential risk to public health and safety of the decommissioning process or would shift the burden of decommissioning funding from ratepayers to taxpayers.") (emphasis added); 61 Fed. Reg. 15427, 15428 (Apr. 8, 1996)("The liability of the licensee to provide funding for decommissioning may adversely affect protection of the public health and safety. Also, a lack of decommissioning funds is a financial risk to taxpayers

[59] *Dominion August 31, 2000 Application for the transfer of the licenses for Millstone Units 1, 2 and 3*, at page 10.

[60] Ibid.

[61] *Calvert Cliffs Nuclear Power Plant Request for a Transfer in Control*, December 20, 2000, at page 9 and *Nine Mile Point Unit Nos. 1 & 2 NRC License Transfer Application*, February 1, 2001, at page 23.

(i.e., if the licensee cannot pay for decommissioning, taxpayers would ultimately pay the bill. (emphasis added)."[62]

In fact, there are a number of possible circumstances in which taxpayers could be asked to bear much, if not all, of the cost of a major power plant accident. First, there is no assurance that the primary tier of insurance would be available to a licensee in the event of an act of terrorism against a nuclear power plant. American Nuclear Insurers has testified that it would only have resources available to provide the primary insurance coverage to cover a single act of terrorism.[63] Thereafter, all licensees would be left without any primary insurance coverage. At that point, licensees might seek recourse in the courts for a finding that domestic terrorism is an "act of war." Acts of war are excluded from coverage under the Price-Anderson Act.[64]

At the same time, the liabilities associated with a nuclear accident are borne by every nuclear power plant owner in the U.S. as a result of the pooling of liabilities for accidents with claims in excess of $200 million. The maximum cost per reactor is $88.085 million (subject to inflation adjustments) in secondary liability. As shown on Table No. 3 below, the liability for nuclear owners with multiple plants, such as Exelon (19 units) and Entergy (10 units), could approach or exceed $1 billion.

Table No. 3
Potential Price Anderson Act Nuclear Insurance Liabilities

Parent Corporation	Maximum Potential Annual Liability	Maximum Potential Total Liability
Exelon Corporation	$163.52 million	$1,440.35 million
Entergy Corporation[65]	$99 million	$872.04 million
Duke Energy	$52.50 million	$462.45 million
Dominion Resources, Inc.	$57.03 million	$502.32 million
Southern Company	$39.16 million	$344.94 million

[62] Legal Memorandum on the "Decommissioning Liability Associated with a Power Reactor License," Goodwin Procter LLP, February 24, 2002, submitted by Entergy Corporation to the Vermont Public Service Board as Exhibit ENVY-Wells-3 to the Prefiled Rebuttal Testimony of Connie Wells in Docket No. 6545.

[63] John Quattocchi, Senior Vice-President, American Nuclear Insurers, February 15, 2002 Response to Question from Senator Reid, Hearing before the Senate Committee on Environment and Public Works, January 23, 2002.

[64] The NRC's "opinion" is that claims arising out of an act of terrorism at a nuclear power plant would not be excluded under the Price Anderson Act. February 13, 2002 NRC Answer to Question No. 3 from Senator Reid, Hearing before the Senate Committee on Environment and Public Works, January 23, 2002. However, the NRC recognizes that a "question of this nature and magnitude" would likely need to be resolved by a court in the first instance.

[65] Potential Liability figures reflect Entergy ownership of the Vermont Yankee Nuclear Station.

TVA	$60 million	$528.51 million
Progress Energy	$44.72 million	$393.87 million
FPL Group[66]	$47.33 million	$416.91 million
Constellation Energy Group, Inc.	$38.20 million	$336.49 million
FirstEnergy	$40 million	$352.34 million

However, under the Atomic Energy Act, a licensee's secondary liability can be deferred if it would constitute an undue hardship on the licensee.[67] In such a situation, the secondary liability that would have been borne by the license would become a taxpayer funded liability. It is not unreasonable to expect that power plant owners, especially those that are thinly capitalized, will try to avail themselves of this deferral should a major accident occur.

Moreover, this Report has focused on nuclear-related issues. Nuclear power plants also contain large amounts of asbestos and large volumes of toxic chemicals. Taxpayers also could be forced to bear the costs of cleaning up for these and any other non-nuclear-related pollutants if a single asset power plant-owning subsidiary was able to successfully declare bankruptcy and a court was unwilling to hold the parent corporation liable.

Finding No. 12 - The NRC has no statutory authority to require a licensee in bankruptcy to continue making safety-related or decommissioning expenditures or to pay retrospective Price-Anderson Act premiums.

NRC regulations require any nuclear power plant licensee to immediately report any filing of a voluntary or involuntary petition for bankruptcy.[68] However, the NRC has no additional financial requirements for situations where a licensee files for bankruptcy or otherwise encounters financial difficulties. Nor does the NRC have any statutory authority to require a licensee which is in bankruptcy to continue to make safety-related or decommissioning payments or to pay retrospective Price-Anderson Act premiums. The NRC must intervene in the proceedings before the bankruptcy court and petition the court to require such payments.

The NRC has acknowledged that the license transfer requirements contained in 10 CFR 50.80 do not specifically or expressly refer to a prospective licensee's ability to meet financial protection payments that may be required under the Price-Anderson Act.[69] However, the NRC has said that 10 CFR 140.21 requires reactor licensees that are covered under the Price-Anderson system to provide annual guarantees of payments of

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[66] Potential Liability figures reflect FPL Group ownership of the Seabrook Nuclear Station.

[67] Atomic Energy Act Section 170(b)(2)(A) and (2)(B).

[68] 10 CFR 50.54 (cc).

[69] NRC February 13, 2002, response to Post-Hearing Question 6 from Senator Reid.

retrospective premiums and that the NRC evaluates an applicants guarantees of payment of retrospective premiums when it considers a license transfer request.[70]

The NRC has further said that it annually reviews the Price-Anderson Act guarantees for all of its power reactor licensees, including those that are LLCs.[71] All of the licensees have, to date, used the cash flow method of guarantee allowed under 10 CFR 140.21; that is, a licensee may demonstrate that it has sufficient cash flow over 3 months to meet an annual $10 million retrospective premium payment for each reactor that it owns.[72] As long as the licensee chooses that method and is able to pass the financial test for cash flow each year, no additional guarantee is required. However, if a licensee were not able to pass the cash flow test, it would have to provide some other allowable guarantee such as surety bonds, letters of credit, revolving credit/term load arrangements, maintenance of escrow deposits of government securities, or such other type of guarantee as might be approved by the NRC.[73] But there is no requirement that the parent corporation provide such a guarantee, only the subsidiary, and there is no requirement that resources be available to pay the maximum of $88.085 million per reactor.

The NRC has stated that under 10 CFR 140, a licensee is required to pay the retrospective premium, notwithstanding its financial status.[74] The NRC also has said that its has had positive experiences with bankruptcy courts that have overseen the Chapter 11 reorganizations of Public Service Company of New Hampshire (Seabrook nuclear plant), Cajun Electric Cooperative (River Bend), El Paso Electric Company (Palo Verde), and Vermont Electric Generation & Transmission Cooperative (Millstone 3).[75] According to the NRC, in each of these cases, the bankruptcy courts allowed these bankrupt licensees to pay all safety-related operational and decommissioning expenses (including, the NRC believes, Price-Anderson primary layer and on-site property insurance premium payments). The NRC also has noted that during its bankruptcy PG&E has continued to meet all safety-related expenses for its nuclear plants.

However, the NRC has acknowledged that it could potentially face a conflict with other claims in a bankruptcy proceeding "if there were an accident sufficient to trigger a retrospective premium assessment. The NRC would presumably require a licensee to pay the assessment, but the bankruptcy court could order the licensee not to pay it."[76]

In addition, the NRC's earlier experience with the bankruptcies all involved entities that owned a number of different assets. The bankruptcy of a single-asset LLC, which owns only a single nuclear power plant, would present very different circumstances and

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[70] NRC February 13, 2002, response to Post-Hearing Question 6 from Senator Reid.

[71] The NRC also requires that each licensee submit an annual financial report, 10 CFR 50.71(b) and a decommissioning fund status report every two years (and annually during the last five years of operation). 10 CFR 50.71(f)(1).

[72] A retrospective premium is insurance that is paid after an accident.

[73] NRC February 13, 2002, response to Post-Hearing Question 8 from Senator Reid.

[74] NRC February 13, 2002, response to Post-Hearing Question 9 from Senator Reid.

[75] NRC February 13, 2002, response to Post-Hearing Question 2 from Senator Inhofe.

[76] NRC February 13, 2002, response to Post-Hearing Question 9 from Senator Reid.

challenges. At the same time, as we will discuss later in this Report, given the multi-tiered holding companies (including LLCs) through which parent corporations now own many nuclear power plants, the NRC might have trouble "piercing the corporate veil" to require a parent of a bankrupt LLC subsidiary to make the required retrospective premium payments.

It is clear that there are no specific statutory or regulatory safeguards in place to ensure that retrospective premiums under the Price-Anderson Act will be available from bankrupt nuclear plant-owning subsidiaries or from their parent corporations. The NRC has sought legislation from Congress to ensure that decommissioning costs receive explicit priority in bankruptcy proceedings. But, so far, that legislation has not been enacted.[77] The NRC has further stated its willingness to support legislation to prioritize safety-related claims in bankruptcy proceedings and to avoid any potential conflict between NRC requirements to pay into the retrospective Price-Anderson Act premium pool and other claims in bankruptcy.[78]

Finding No. 13 – Case law suggests that it would be very difficult to hold a parent corporation responsible for the liabilities incurred by nuclear power plant owning LLC subsidiaries in a multi-tiered holding company.

As mentioned earlier in this Report, the multiple layers of subsidiaries, including LLCs, that have been created by parent corporations in the nuclear industry are a cause of serious concern. Even if a court concludes that the liability of the subsidiary that actually operates the nuclear plant should be extended to business structures above it (for example, if under capitalization and profit distributions have left the subsidiary unable to cover the costs of unanticipated repairs or security improvements and the subsidiary decides to cease operations), the ability of the court to find a senior business entity with sufficient capital could be complicated by multiple layers of subsidiaries and LLCs. There may be issues of jurisdiction, applicable state or federal statutes, the role of the NRC, and other myriad issues of law and fact that would need to be resolved. Given that the presumption in every state and federal statute is for the limitation of corporate liability, the burden is always on the party trying to extend that liability to show that the law, facts, and public policy all support violating the statutory presumption.[79] Courts, in

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[77] The Energy Policy Act of 2002 (HR 4), as approved by the U.S. Senate, amends the U.S. Bankruptcy Code to prevent creditors in a bankruptcy proceeding from attaching an NRC licensee's decommissioning funds until the decommissioning has been completed. The Senate enacted provision also seeks to prevent creditors from using Price-Anderson insurance and those deferred premiums held in reserve to satisfy creditors. However, neither version of the Energy Policy Act of 2002, that enacted by the House or the Senate, would require a parent corporation or other guarantor to commit resources in the event that there are not adequate resources within a bankrupt LLC to satisfy claims after a nuclear accident. Post accident liabilities could shift to taxpayers in this case.

[78] NRC February 13, 2002, response to Post-Hearing Question 9 from Senator Reid.

[79] "Piercing the Corporate Veil: An Empirical Study", Robert B. Thompson, 76 Cornell Law Review 1036 (1991), Section II, and "Limited Liability and the Corporation", Frank H. Easterbrook and Daniel R. Fishel, 52 U. Chi. L. Rev. 89 (1985), Section IV.

general, are reluctant to pierce the corporate veil and extend liability; when multiple corporations are involved, that reluctance only increases.

Despite the limitations on corporate liability embodied in statutes, there are numerous instances where courts have been willing to ignore those limitations under a wide range of factual circumstances. The case law varies a great deal from one state to another, but all of them involve some rationale for "piercing the corporate veil" and holding the owners of the corporation personally liable. For the purposes of this Report, it is important to note that in the nuclear power industry, the owners of a nuclear power plant-owning LLC subsidiary are most likely to be another LLC or a parent corporation. The objective of the effort to pierce the corporate veil in this situation would be to make the parent corporation responsible for the liability of the LLC subsidiary.

There is an enormous volume of litigation over the issue of extending liability through to the owners of a corporation. The case law is varied and complex and a thorough and complete review is beyond the scope of this project. What follows is a summary of the common themes that have been used by a variety of courts for extending liability.[80]

Starting from a presumption that a corporation's liability is limited, facts must be presented to justify extending liability. Some of the fact situations that have been persuasive to courts are the following:

- Corporate form is used as a front for illegal or fraudulent activity. In these cases, courts express no reluctance in holding individuals liable for the debts of the corporation since there is no public policy that seeks to support such activities under any business structure.
- Corporate form is used as a sham or a mere shell to avoid liability. In these cases, the individuals or parent corporation are aware from the start that the corporation is unlikely to ever repay its debts or liabilities and seek to acquire as much income as possible before creditors foreclose.
- Individual owners subvert the corporation for their personal gain. In these cases, the personal enrichment may or may not be based on illegal or unethical actions. If the facts establish that owners personally benefited from corporate activities (beyond the normal sharing of corporate profits), then courts are generally willing to make them personally liable. These cases often involve members of the Board of Directors or managers. Corporate owners who do not personally benefit but are aware of the enrichment of other owners can be held personally liable based on their breach of their fiduciary responsibilities to the corporation.
- Under-capitalization of the corporation. In these cases, there is a determination that at the time of incorporation, or due to subsequent management actions, there is insufficient capital available for the business activities of the corporation. Although similar to the problem of a sham corporation, the decision by the court

[80] Id., Thompson at 1063-1072; Easterbrook at 109-113.

involves a more objective analysis of appropriate levels of capitalization for similar entities engaged in similar activities.

- Improper distributions of income. These cases involve decisions by the corporate management, usually the Board of Directors, to distribute corporate income to shareholders in a financially irresponsible manner that leaves the corporation unable to meet its obligations. These are very fact-specific litigations that involve a great deal of hindsight analysis. However, if the facts show a clear pattern of irresponsibility, as opposed to poor business decisions, courts will extend liability to specific individuals or the corporation in general.
- Interference in management. These cases involve situations where owners, often large stockholders in closely held corporations, become so involved in corporate management that they look more like a managing partner than just an investor. Courts will extend liability to these "investors" on the theory that they do not deserve the normal corporate protection.
- Environmental, regulatory, or public policy. These factors are often included with one or more of the above fact patterns to support extending liability. It is unusual for a court to invoke "public policy" by itself as a justification for piercing the corporate veil.

An empirical study of court decisions where piercing the veil issues were litigated indicates that courts are very reluctant to impute liability to the shareholders of public corporations. Closely-held corporations (non-public and usually with few investors) and related corporate entities (subsidiaries, affiliates, etc.) are the forms to which courts have applied extended liability.[81]

There is very little case law involving LLCs that specifically addresses piercing the corporate veil due to the relatively short time period (fifteen years) during which LLC structures have been developed. Consequently, there is great uncertainty as to the effect that having one or more LLCs in the ownership chain within a holding company will have on the willingness of a court to pierce the corporate veil in order to hold a parent company responsible for the liabilities of its indirect nuclear power plant owning-subsidiary.

Finding No. 14 - The NRC has expressed serious doubts as to its ability to hold a parent corporation responsible for the liabilities incurred by a subsidiary.

There are two NRC cases that involved attempts to pierce the corporate veil of the operator of a nuclear power plant. In 1995, the NRC attempted to negate a transfer of assets from a licensee which, as part of a complicated corporate restructuring, had become a subsidiary to a newly created holding company because the transfer had occurred without the prior written consent of the NRC, as required by section 184 of the Atomic Energy Act. The NRC held that it could pierce the veil of corporations that

[81] Id., Thompson at 1070.

violate section 184. However, before a final adjudication, this case ended in a settlement.[82]

In 1997, the NRC tried to force a parent company to provide additional funds to the decommissioning fund for a subsidiary plant. However, prior to a final adjudication, the NRC approved a settlement that resolved the decommissioning fund issue without any specific finding as to the parent company's liability.[83] In accepting the settlement, the NRC expressed concern that there was a "substantial possibility of defeat if the case proceeds to trial [on a theory of] piercing the corporate veil."

Both cases were cited in a legal memorandum provided by the current owners of the Vermont Yankee Nuclear Power Corporation, which concluded that attempts to pierce the corporate veil of nuclear power plant subsidiaries were unlikely to succeed and have seldom been attempted.[84] Despite the numerous specific instances where courts have extended liability to parent corporations, there is great uncertainty as to whether or not courts would apply such extended liability to multi-layered nuclear power companies.

Finding No. 15 – Shielding parent corporations from nuclear power plant operating and decommissioning risks is unfair and economically inefficient.

To the extent that the organizational structures discussed above serve to successfully shield the parent company from risks, they are inequitable and undermine efficient decision-making.

As a matter of fairness, individuals and companies should take responsibility for cleaning up after themselves. If an unanticipated problem in operation causes a nuclear plant to experience an extended or permanent outage prior to the end of its operating license or if the decommissioning of a plant turns out to cost more than expected, then the parent company may decide to provide additional resources to the subsidiary in order to carry out the subsidiaries responsibilities. On the other hand, the parent company may not. If there are clean up costs which the subsidiary is unwilling to bear, then these may fall upon taxpayers. Considerations of fairness would have the company that profited (or expected to profit) from plant operation bear the costs of cleaning up the facility.

This is also a matter of economic efficiency. If a company is protected from significant risks associated with its decisions, then there is what economists call an "externality." A reasonable definition of externality is provided in a popular economics textbook as follows:

> An externality or spillover effect occurs when production or consumption inflicts involuntary costs or benefits on others; that is, costs or benefits are

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[82] *Safety Light Corp.*, 41 N.R.C. at 457-458 (1995).

[83] *Sequoyah Fuels Corp. and General Atomics*, CLI-97-13, 46N.R.C. 195 (1997).

[84] Vermont Yankee Memorandum of Law Regarding Ratepayer Risk of Liability for Vermont Yankee Decommissioning Costs, Vermont Public Service Board Docket No. 6545, dated February 25, 2002, at pages 17 and 18.

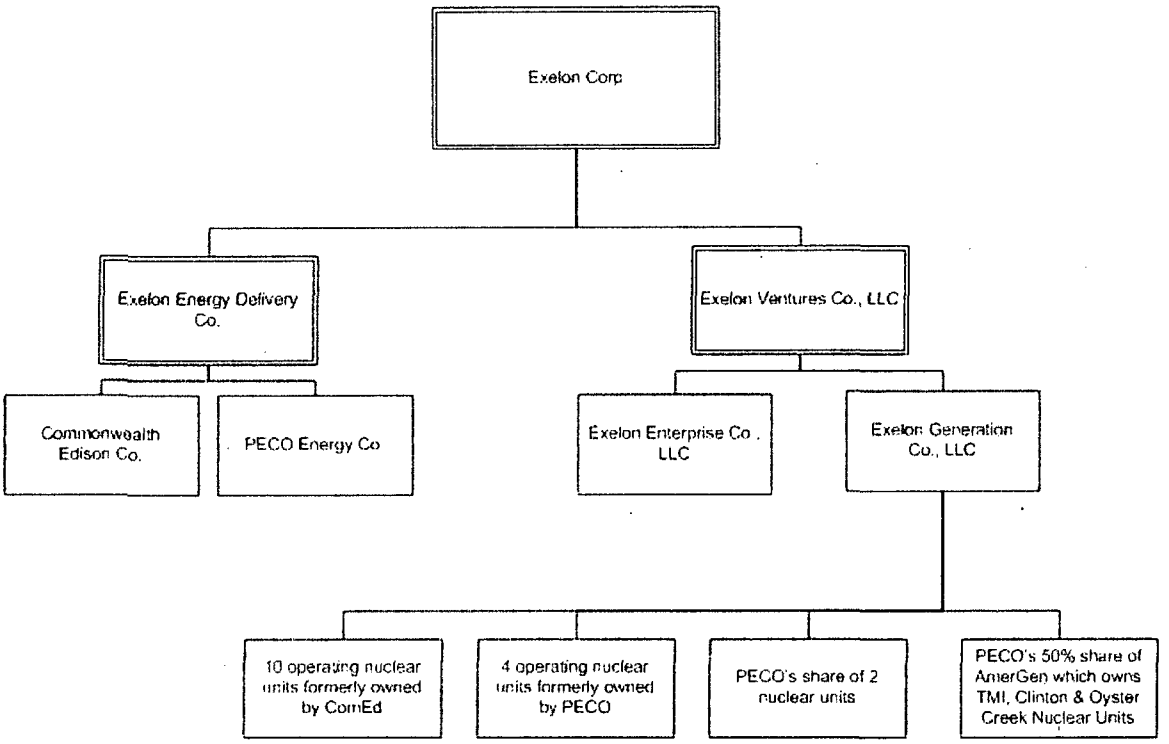
> imposed on others yet are not paid for by those who impose them or receive them. More precisely, an externality is an effect of one economic agent's behavior on another's well-being, where that effect is not reflected in dollar or market transactions.[85]

Where there are such externalities, private decision-making will be inefficient. A company will tend to undervalue (or value at zero) the costs associated with its action that are borne by others. In the case of a nuclear power plant, the protection from liability may, for example, cause the operator to make decisions that undervalue the potential for long-term radioactive waste storage costs. Or, faced with operating decisions that involve tradeoffs between cost and safety, the owner may undervalue safety and make choices that strike the wrong balance. In these situations, because some of the risks are "external," the market outcome may be an inappropriate decision from a societal perspective – or an inefficient allocation of resources. Government policy efforts should aim to internalize externalities, in order to promote appropriate private decision-making and efficient resource allocation.

[85] Samuelson, Paul A. and William D. Nordhaus. 1989. Economics, 13th Edition. McGraw-Hill, at page 770.

ATTACHMENT NO. 1

Exelon Corporation

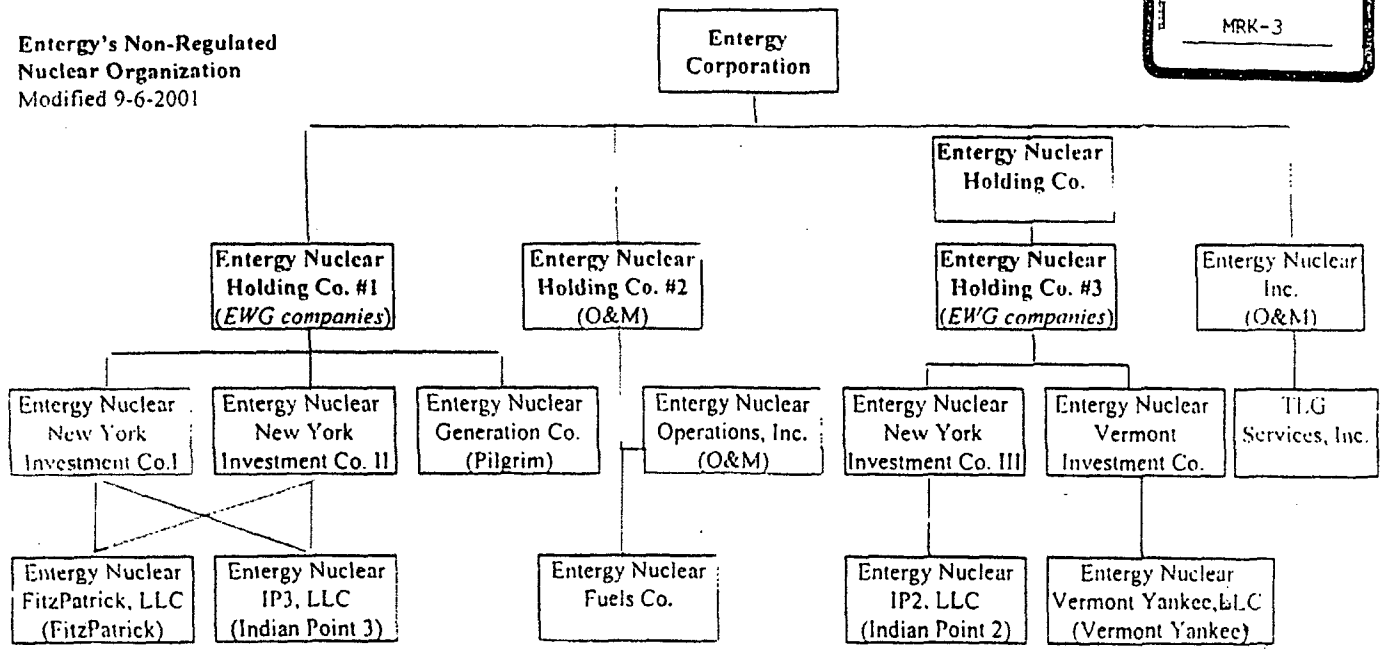


EXH. .T
MRK-3

ATTACHMENT NO. 2

Entergy Corporation – Non-regulated Nuclear Organization

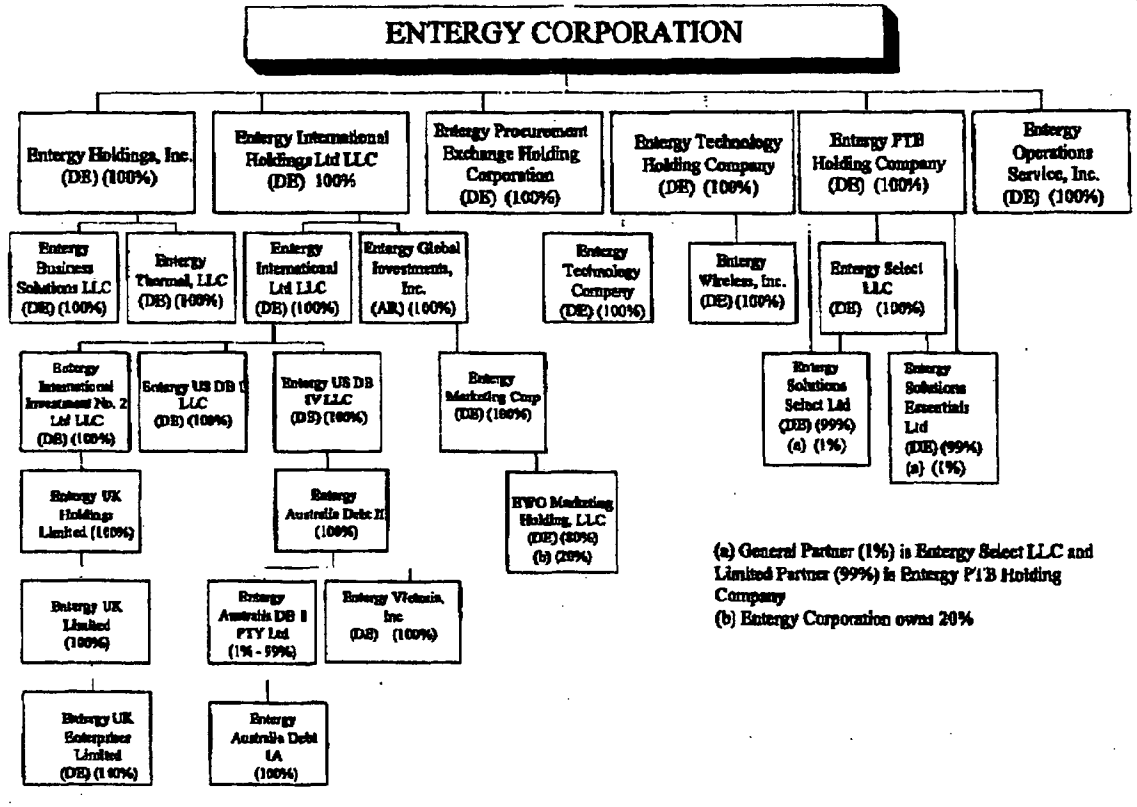
Entergy's Non-Regulated Nuclear Organization
Modified 9-6-2001



Exempt Wholesale Generator (EWG)
Operations and Maintenance (O&M)

ATTACHMENT NO. 3

Entergy Corporation



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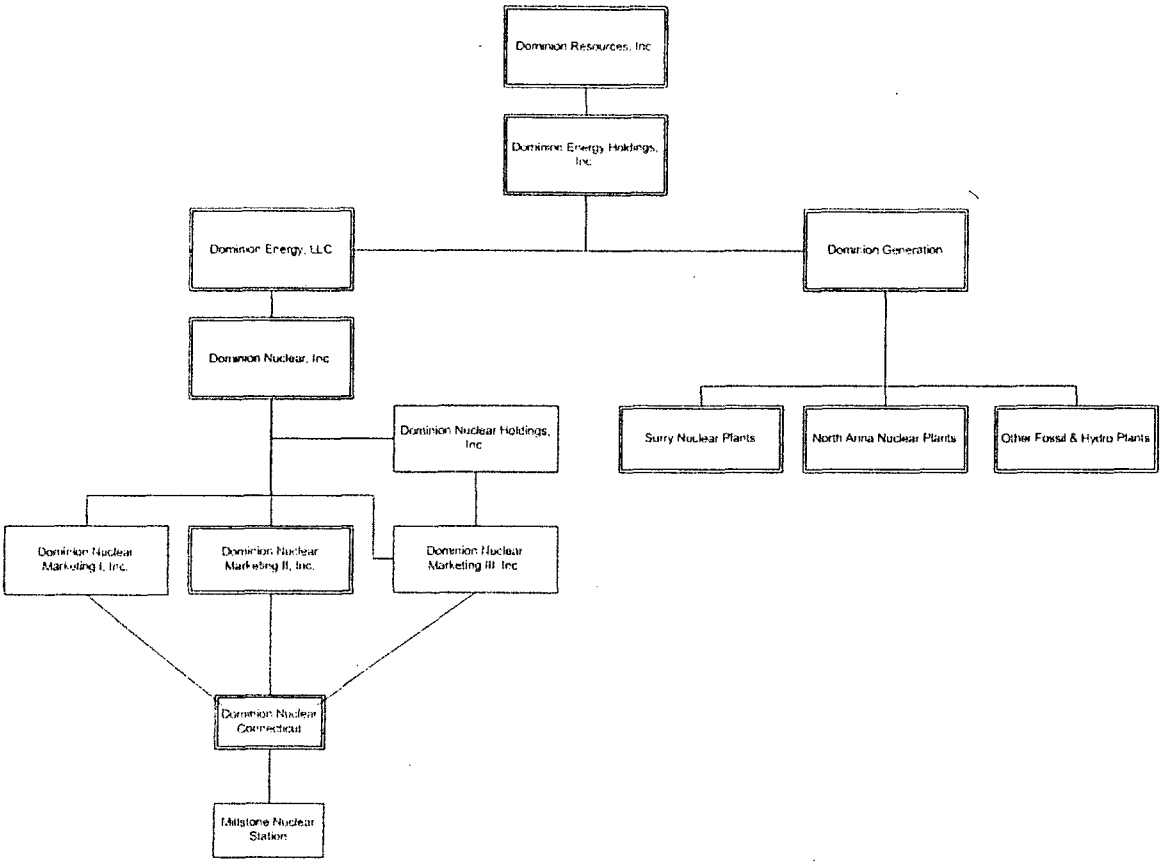
ATTACHMENT NO. 4

Dominion Resources, Inc.



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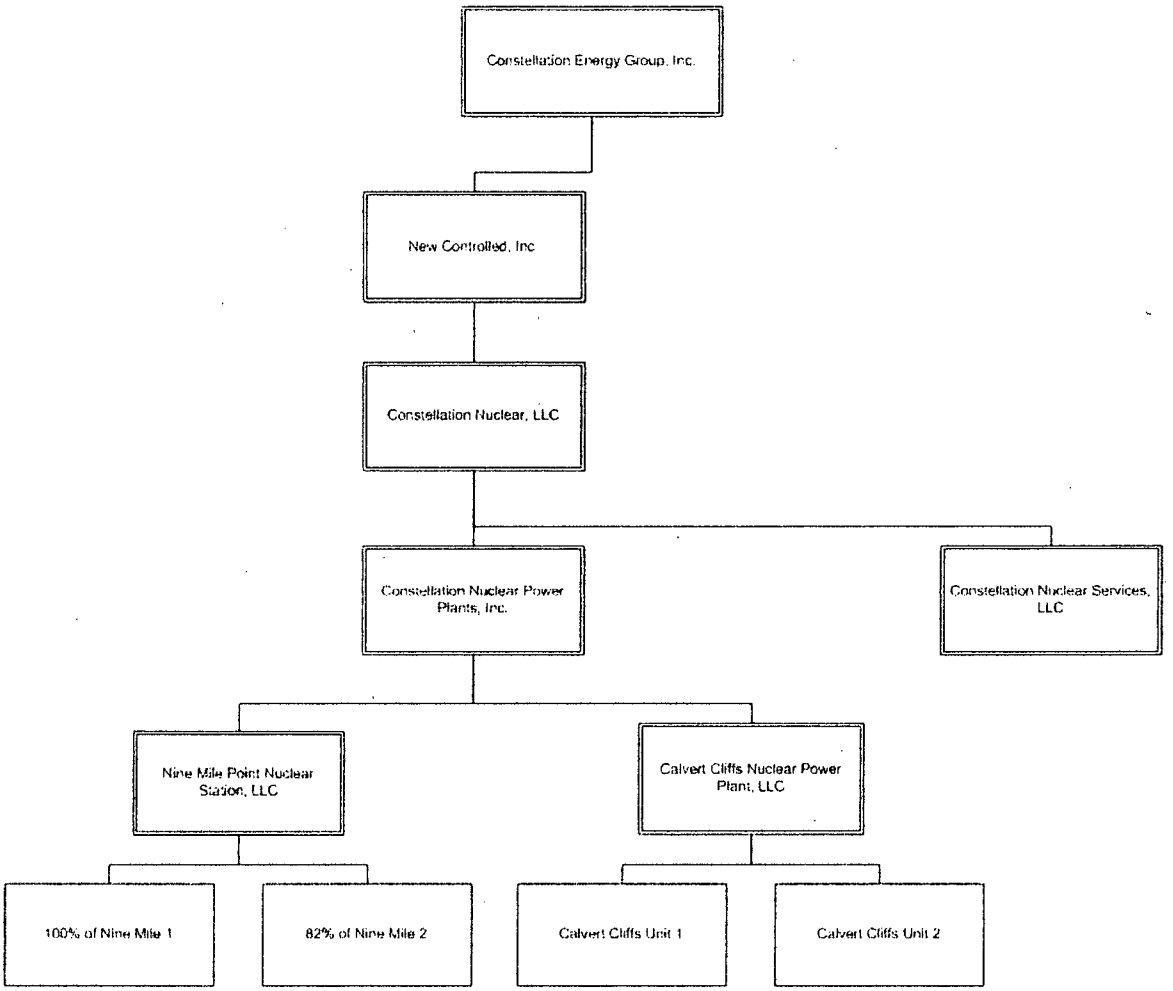

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PG&E Corporation

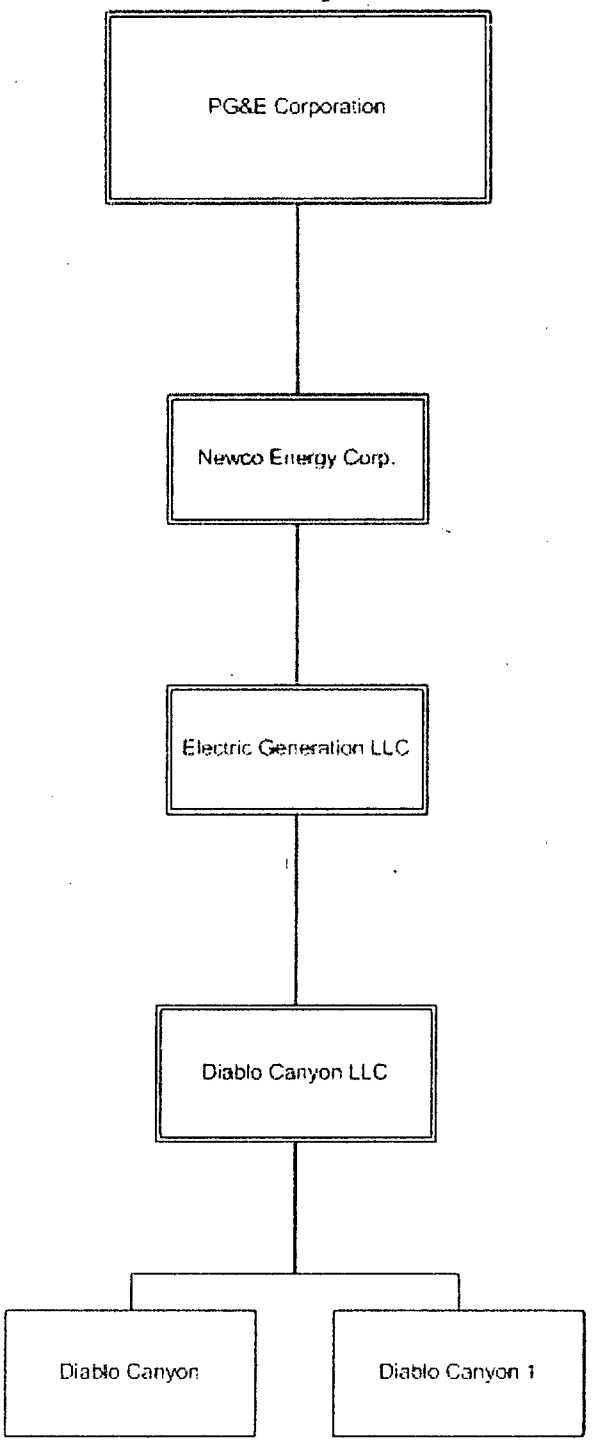

EXHIBIT EE

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CRS Report for Congress

Received through the CRS Web

Nuclear Power Plants: Vulnerability to Terrorist Attack

Carl Behrens and Mark Holt
Specialists in Energy Policy
Resources, Science, and Industry Division

Summary

Protection of nuclear power plants from land-based assaults, deliberate aircraft crashes, and other terrorist acts has been a heightened national priority since the attacks of September 11, 2001. The Nuclear Regulatory Commission (NRC) has strengthened its regulations on nuclear reactor security, but critics contend that implementation by the industry has been too slow and that further measures are needed. Several provisions to increase nuclear reactor security are included in the Energy Policy Act of 2005, signed August 8, 2005. The new law requires NRC to conduct "force on force" security exercises at nuclear power plants at least once every three years and to revise the "design-basis threat" that nuclear plant security forces must be able to meet, among other measures. This report will be updated as events warrant.

Nuclear power plants have long been recognized as potential targets of terrorist attacks, and critics have long questioned the adequacy of the measures required of nuclear plant operators to defend against such attacks. Following the September 11, 2001, attacks on the Pentagon and the World Trade Center, the Nuclear Regulatory Commission (NRC) began a "top-to-bottom" review of its security requirements. On February 25, 2002, the agency issued "interim compensatory security measures" to deal with the "generalized high-level threat environment" that continued to exist, and on January 7, 2003, it issued regulatory orders that tightened nuclear plant access. On April 29, 2003, NRC issued three orders to restrict security officer work hours, establish new security force training and qualification requirements, and increase the "design basis threat" that nuclear security forces must be able to defeat.

Security Regulations

Under the regulations in place prior to the September 11 attacks, all commercial nuclear power plants licensed by NRC must be protected by a series of physical barriers and a trained security force. The plant sites are divided into three zones: an "owner-controlled" buffer region, a "protected area," and a "vital area." Access to the protected area is restricted to a portion of plant employees and monitored visitors, with stringent

access barriers. The vital area is further restricted, with additional barriers and access requirements. The security force must comply with NRC requirements on pre-hiring investigations and training.[1]

Design Basis Threat. The severity of attacks to be prepared for are specified in the form of a "design basis threat" (DBT). One of NRC's April 2003 regulatory orders changed the DBT to "represent the largest reasonable threat against which a regulated private guard force should be expected to defend under existing law," according to the NRC announcement. The details of the revised DBT, which took effect October 29, 2004, were not released to the public.

NRC requires each nuclear power plant to conduct periodic security exercises to test its ability to defend against the design basis threat. In these "force on force" exercises, monitored by NRC, an adversary force from outside the plant attempts to penetrate the plant's vital area and damage or destroy key safety components. Participants in the tightly controlled exercises carry weapons modified to fire only blanks and laser bursts to simulate bullets, and they wear laser sensors to indicate hits. Other weapons and explosives, as well as destruction or breaching of physical security barriers, may also be simulated. While one squad of the plant's guard force is participating in a force-on-force exercise, another squad is also on duty to maintain normal plant security. Plant defenders know that a mock attack will take place sometime during a specific period of several hours, but they do not know what the attack scenario will be. Multiple attack scenarios are conducted over several days of exercises.

Full implementation of the force-on-force program coincided with the effective date of the new DBT in late 2004. Standard procedures and other requirements have been developed for using the force-on-force exercises to evaluate plant security and as a basis for taking regulatory enforcement action. Many tradeoffs are necessary to make the exercises as realistic and consistent as possible without endangering participants or regular plant operations and security. Each plant is required to conduct NRC-monitored force-on-force exercises once every three years.

NRC required the nuclear industry to develop and train a "composite adversary force" comprising security officers from many plants to simulate terrorist attacks in the force-on-force exercises. However, in September 2004 testimony, the Government Accountability Office (GAO) criticized the industry's selection of a security company that guards about half of U.S. nuclear plants, Wackenhut, to also provide the adversary force. In addition to raising "questions about the force's independence," GAO noted that Wackenhut had been accused of cheating on previous force-on-force exercises by the Department of Energy.[2]

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[1] General NRC requirements for nuclear power plant security can be found at 10 CFR 73.55.

[2] Government Accountability Office. *Nuclear Regulatory Commission: Preliminary Observations on Efforts to Improve Security at Nuclear Power Plants.* Statement of Jim Wells, Director, Natural Resources and Environment, Government Accountability Office, to the Subcommittee on National Security, Emerging Threats, and International Relations, House Committee on Government Reform. September 14, 2004. p. 14.

Congress imposed statutory requirements for the DBT and force-on-force exercises in the Energy Policy Act of 2005, signed August 8, 2005. The act requires that each nuclear plant undergo force-on-force exercises at least once every three years (NRC's current policy), that the exercises simulate the threats in the DBT, and that NRC "mitigate any potential conflict of interest that could influence the results of a force-on-force exercise, as the Commission determines to be necessary and appropriate."

The new law requires NRC to revise the DBT within 18 months, after considering a wide variety of potential modes of attack (physical, chemical, biological, etc.), the potential for large attacks by multiple teams, potential assistance by several employees inside a facility, the effects of large explosives and other modern weaponry, and other specific factors.

Emergency Response. After the 1979 accident at the Three Mile Island nuclear plant near Harrisburg, PA, Congress required that all nuclear power plants be covered by emergency plans. NRC requires that within an approximately 10-mile Emergency Planning Zone (EPZ) around each plant the operator must maintain warning sirens and regularly conduct evacuation exercises monitored by NRC and the Federal Emergency Management Agency (FEMA). In light of the increased possibility of terrorist attacks that, if successful, could result in release of radioactive material, critics have renewed calls for expanding the EPZ to include larger population centers.

Another controversial issue regarding emergency response to a radioactive release from a nuclear power plant is the distribution of iodine pills. A significant component of an accidental or terrorist release from a nuclear reactor would be a radioactive form of iodine, which tends to concentrate in the thyroid gland of persons exposed to it. Taking a pill containing non-radioactive iodine before exposure would prevent absorption of the radioactive iodine. Emergency plans in many states include distribution of iodine pills to the population within the EPZ, which would protect from exposure to radioactive iodine, although giving no protection against other radioactive elements in the release. NRC in 2002 began providing iodine pills to states requesting them for populations within the 10-mile EPZ.

Nuclear Plant Vulnerability

Operating nuclear reactors contain large amounts of radioactive fission products which, if dispersed, could pose a direct radiation hazard, contaminate soil and vegetation, and be ingested by humans and animals. Human exposure at high enough levels can cause both short-term illness and death, and longer-term deaths by cancer and other diseases.

To prevent dispersal of radioactive material, nuclear fuel and its fission products are encased in metal cladding within a steel reactor vessel, which is inside a concrete "containment" structure. Heat from the radioactive decay of fission products could melt the fuel-rod cladding even if the reactor were shut down. A major concern in operating a nuclear power plant, in addition to controlling the nuclear reaction, is assuring that the core does not lose its coolant and "melt down" from the heat produced by the radioactive fission products within the fuel rods. Therefore, even if plant operators shut down the reactor as they are supposed to during a terrorist attack, the threat of a radioactive release would not be eliminated.

Commercial reactor containment structures — made of steel-reinforced concrete several feet thick — are designed to prevent dispersal of most of a reactor's radioactive material in the event of a loss of coolant and meltdown. Without a breach in the containment, and without some source of dispersal energy such as a chemical explosion or fire, the radioactive fission products that escaped from the melting fuel cladding mostly would remain where they were. The two major meltdown accidents that have taken place in power reactors, at Three Mile Island in 1979 and at Chernobyl in the Soviet Union in 1986, illustrate this phenomenon. Both resulted from a combination of operator error and design flaws. At Three Mile Island, loss of coolant caused the fuel to melt, but there was no fire or explosion, and the containment prevented the escape of substantial amounts of radioactivity. At Chernobyl, which had no containment, a hydrogen explosion and a fierce graphite fire caused a significant part of the radioactive core to be blown into the atmosphere, where it contaminated large areas of the surrounding countryside and was detected in smaller amounts literally around the world.

Vulnerability from Air Attack. Nuclear power plants were designed to withstand hurricanes, earthquakes, and other extreme events, but attacks by large airliners loaded with fuel, such as those that crashed into the World Trade Center and Pentagon, were not contemplated when design requirements were determined. A taped interview shown September 10, 2002, on Arab TV station al-Jazeera, which contains a statement that Al Qaeda initially planned to include a nuclear plant in its 2001 attack sites, intensified concern about aircraft crashes.

In light of the possibility that an air attack might penetrate the containment building of a nuclear plant, some interest groups have suggested that such an event could be followed by a meltdown and widespread radiation exposure. Nuclear industry spokespersons have countered by pointing out that relatively small, low-lying nuclear power plants are difficult targets for attack, and have argued that penetration of the containment is unlikely, and that even if such penetration occurred it probably would not reach the reactor vessel. They suggest that a sustained fire, such as that which melted the structures in the World Trade Center buildings, would be impossible unless an attacking plane penetrated the containment completely, including its fuel-bearing wings.

Recently completed NRC studies "confirm that the likelihood of both damaging the reactor core and releasing radioactivity that could affect public health and safety is low," according to NRC Chairman Nils Diaz. However, NRC is considering studies of additional measures to mitigate the effects of an aircraft crash.[3]

Spent Fuel Storage. Radioactive "spent" nuclear fuel — which is removed from the reactor core after it can no longer efficiently sustain a nuclear chain reaction — is stored in pools of water in the reactor building or in dry casks elsewhere on the plant grounds. Because both types of storage are located outside the reactor containment structure, particular concern has been raised about the vulnerability of spent fuel to attack by aircraft or other means. Spent fuel pools and dry cask storage facilities are subject to NRC security requirements.

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[3] Letter from NRC Chairman Nils J. Diaz to Secretary of Homeland Security Tom Ridge, September 8, 2004.

The primary concern is whether terrorists could breach the thick concrete walls of a spent fuel pool and drain the cooling water, which could cause the spent fuel's zirconium cladding to overheat and catch fire. A report released in April 2005 by the National Academy of Sciences (NAS) found that "successful terrorist attacks on spent fuel pools, though difficult, are possible," and that "if an attack leads to a propagating zirconium cladding fire, it could result in the release of large amounts of radioactive material." NAS recommended that the hottest spent fuel be interspersed with cooler spent fuel to reduce the likelihood of fire, and that water-spray systems be installed to cool spent fuel if pool water were lost. The report also called for NRC to conduct more analysis of the issue and consider earlier movement of spent fuel from pools into dry storage.[4]

Both the House- and Senate-passed versions of the FY2006 Energy and Water Development appropriations bill (H.R. 2419, H.Rept. 109-86, S.Rept. 109-84) would provide $21 million for NRC to carry out the NAS recommendations. The House Appropriations Committee was particularly critical of NRC's actions on spent fuel storage security: "The Committee expects the NRC to redouble its efforts to address the NAS-identified deficiencies, and to direct, not request, industry to take prompt corrective actions."

Regulatory and Legislative Proposals

Critics of NRC's security measures have demanded both short-term regulatory changes and legislative reforms.

A fundamental concern was the nature of the DBT, which critics contended should be increased to include a number of separate, coordinated attacks. Critics also contended that nearly half of the plants tested in NRC-monitored mock attacks before 9/11 failed to repel even the small forces specified in the original DBT, a charge that industry sources vigorously denied. Critics also pointed out that licensees are required to employ only a minimum of five security personnel on duty per plant, which they argue is not enough for the job.[5] Nuclear spokespersons responded that the actual security force for the nation's 65 nuclear plant sites numbers more than 5,000, an average of about 75 per site (covering multiple shifts). Nuclear plant security forces are also supposed to be aided by local law enforcement officers if an attack occurs.

In February 2002, NRC implemented what it called "interim compensatory security measures," including requirements for increased patrols, augmented security forces and capabilities, additional security posts, installation of additional physical barriers, vehicle checks at greater stand-off distances, enhanced coordination with law enforcement and military authorities, and more restrictive site access controls for all personnel. The further

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[4] National Academy of Sciences, Board on Radioactive Waste Management, *Safety and Security of Commercial Spent Nuclear Fuel Storage, Public Report* (online version), released April 6, 2005.

[5] 10 CFR 73.55 (h)(3) states: "The total number of guards, and armed, trained personnel immediately available at the facility to fulfill these response requirements shall nominally be ten (10), unless specifically required otherwise on a case by case basis by the Commission; however, this number may not be reduced to less than five (5) guards."

orders issued April 29, 2003, expanded on the earlier measures, including revising the DBT, which critics continue to describe as inadequate. Continuing congressional concerns resulted in the new criteria in the Energy Policy Act of 2005 for further DBT revisions.

Because of the growing emphasis on security, NRC established the Office of Nuclear Security and Incident Response on April 7, 2002. The office centralizes security oversight of all NRC-regulated facilities, coordinates with law enforcement and intelligence agencies, and handles emergency planning activities. Force-on-force exercises are an example of the office's responsibilities. On June 17, 2003, NRC established the position of Deputy Executive Director for Homeland Protection and Preparedness, whose purview includes the Office of Nuclear Security and Incident Response.

Legislation. Since the 9/11 attacks, numerous legislative proposals, including some by NRC, have focused on nuclear power plant security issues. Several of those ideas, such as the revision of the design-basis threat and the force-on-force security exercises, were included in the Energy Policy Act of 2005, which also includes:

- assignment of a federal security coordinator for each NRC region;
- backup power for nuclear plant emergency warning systems;
- tracking of radiation sources;
- fingerprinting and background checks for nuclear facility workers;
- authorizing use of firearms by nuclear facility security personnel (preempting some state restrictions);
- authorizing NRC to regulate dangerous weapons at licensed facilities;
- extending penalties for sabotage to cover nuclear facilities under construction;
- requiring a manifest and personnel background checks for import and export of nuclear materials; and
- requiring NRC to consult with the Department of Homeland Security on the vulnerability to terrorist attack of locations of proposed nuclear facilities before issuing a license.

A number of legislative proposals introduced since 9/11 to increase nuclear plant security were not included in the new law, including the creation of a federal force within the NRC to replace the private guards at nuclear power plants, requiring emergency planning exercises within a 50-mile radius around each nuclear plant, and stockpiling iodine pills for populations within 200 miles of nuclear plants. Other measures proposed but not enacted include a task force to review security at U.S. nuclear power plants and a federal team to coordinate protection of air, water, and ground access to nuclear power plants.

March 27, 2007

Re: NRC Proposed Rule: Power Reactor Security Requirements (RIN 3150-AG63)

Annette Vietti-Cook, Secretary
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Attn: Rulemakings and Adjudications Staff
Submitted via e-mail to SECY@nrc.gov

COUNCIL ON INTELLIGENT ENERGY & CONSERVATION POLICY (CIECP) COMMENTS TO PROPOSED RULE 10 CFR PARTS 50, 72 AND 73 REGARDING POWER REACTOR SECURITY REQUIREMENTS AT LICENSED NUCLEAR FACILITIES

Nearly six years after September 11, 2001, the 103 civilian nuclear reactors in the United States are still not in a position to repel attacks by adversaries with capabilities commensurate with those of either the 9/11 terrorists or with enemies of the United States currently operative on the world stage. The present Power Reactor Security Requirements (PRSR) thus fall far short of the actual threat level faced by the U.S. today, much less the escalated level the nation will face as nations such as Russia, China and Iran improve and export nuclear engineering expertise. Indeed, as numerous security experts have pointed out, a terrorist group with access to sympathetic nuclear scientists and engineers would have sufficient sophistication to target the critical systems and weak links of nuclear reactors. The assistance that Pakistani nuclear scientists reportedly offered to Al Qaeda illustrates this threat.

Recent National Intelligence Estimates and National Intelligence Council Reports describe the terrorist threat to the U.S. as real and as having no sign of abatement for many years to come. These reports further warn of a new class of "professionalized" terrorists -in part created by the Iraq war- who must be expected to have strong technical skills and English language proficiency. Such individuals should, in the future, be expected to become major players in international terrorism.

Al Qaeda and other terrorist groups have shown extraordinary tactical ingenuity and a complete lack of reverence for human life. Further there is ample evidence that U.S. nuclear power plants, particularly those sited near metropolitan areas, are viewed as attractive terrorist targets. Notably, the 9/11 Commission learned that the original plan for a terrorist spectacular was for a larger strike, using more planes, and including an attack on nuclear power plants. In an Al-Jazeera broadcast in 2002, one of the planners of 9/11 said that a nuclear plant was the initial target considered. We also know from the 9/11 Commission's investigation that, even after the plot was scaled down, when Mohammed Atta was conducting his surveillance flights he spotted a nuclear power plant (unidentified by name, but obviously the Indian Point nuclear power plant) and came close to redirecting the strike. National Research Council analyses and post-9/11 intelligence has also indicated that the U.S. nuclear infrastructure is viewed as an alluring target for a future terrorist spectacular. As the Chairman of the National Intelligence Council stated in 2004, nuclear power plants "are high on Al Qaeda's targeting list," adding that the methods of Al Qaeda and other terrorist group may be "evolving."

There is, thus, every reason to believe that a sizable, well-planned and orchestrated military operation against a U.S. nuclear facility is well within both present and near-future terrorist intent and capability. In view of these realities, the current proposed PRSR is utterly inadequate.

Consequently, the COUNCIL ON INTELLIGENT ENERGY & CONSERVATION POLICY (CIECP) urges the NRC to address the following realities in its PRSR:

ACTIVE INSIDERS

The voluminous number of security breaches which have occurred at critical infrastructure, including nuclear weapons and power facilities after 9/11 (such as the 16 foreign-born construction workers who

were able to gain access to the Y-12 nuclear weapons plant with falsified documentation) demonstrates that nuclear "insiders" must be deemed potential active participants in an attack.

This threat is significantly augmented by nuclear power plant operators' increasing outsourcing of on-site work in order to cut costs.

Contractor oversight failures have been documented by the NRC. For example a December 22, 2003 NRC Special Inspection Report on the Indian Point Nuclear Generating Station in Buchanan, New York (Indian Point) operated by Entergy Nuclear Northeast (Entergy) notes "the common theme of a lack of direct contractor oversight and quality control measures, along with the absence of Entergy subject matter experts to independently assess contracted work activities...." Critically, the risk of sabotage is elevated at all power plants during periods of refueling and major construction work when hundreds of outside contract workers have site access.

The active participation of insiders, including contract workers, in a terrorist offensive need not take place during the time of attack. It may occur days or even many months prior to an attack. In addition to actions such as surveillance of plant schematics, security features and protocols, pre-attack participation may involve the sabotage of critical instrumentation, computers, piping, electronic systems or any number of other components, where such sabotage would likely not be discovered prior to an emergency event.

COMPUTER SYSTEM COMPROMISE

Nuclear power plant computer systems, like those of other critical infrastructure, are subject to a range of vulnerabilities, including power outages, attacks by malicious hackers, viruses and worms. Compromise of integrity may also occur at the level of software development via backdoors written into code or the implantation of logic bombs programmed to shut down a safety system at a particular time.

Many terrorist networks have the resources and technical savvy to wreak havoc. For example, the alleged terrorist, Muhammad Naeem Noor Khan, picked up in Pakistan in 2004, and believed to have links with Al Qaeda, is a computer engineer.

The fact that U.S. nuclear reactors are not impregnable was demonstrated by the penetration of the Slammer worm into the Davis-Besse nuclear facility. That intrusion disabled a safety monitoring system for nearly 5 hours. In addition, computer hackers have broken into U.S. Department of Energy computers. Some of such intrusions were root-level compromises, indicating that hackers had enough access to install viruses.

Computers at nuclear power stations are also vulnerable to acts of sabotage against off-site power transmission, as was evidenced at Indian Point during the 2003 blackout which struck the Northeast. At Indian Point, various computer systems had to be removed from service, including the Critical Function Monitoring System, the Local Area Network, the Safety Assessment System/Emergency Data Display System, the Digital Radiation Monitoring System and the Safety Assessment System.

It is, accordingly, a matter of pressing importance that the NRC engage independent experts to develop a comprehensive computer vulnerability and cyber-attack threat assessment. Such an assessment must evaluate the vulnerability of the full range of nuclear power plant computer systems and the potential consequences of such vulnerabilities. The PRSR must incorporate such findings and include a protocol for quickly detecting such an attack and recovering key computer functions in the event of an attack.

CHEMICAL WEAPONS

The PRSR must fully address the potential consequences of the use of toxic chemicals as part of an attack scenario. There are numerous agents that can be deployed with almost instantaneous effect and can immobilize targets via paralysis, convulsions, blinding, suffocation or death. Such agents could be employed as part of the initialization strategy. For, example, a truck or even large SUV filled with chlorine, boron trifluoride, hydrofluoric acid, liquid ammonia, or any number of other agents could be crashed into a perimeter barrier, with the resulting fumes killing or disabling plant personnel guarding the outdoor area of the facility.

Chemical agents could also be introduced surreptitiously into building ventilation systems. They may also be used strategically to neutralize workers endeavoring to maintain control of the situation.

Many such agents are easy to make and do not require sophisticated delivery systems. Some can be carried in coffee mugs or in vials within body cavities. Phenarsazine chloride, an arsenic derivative, can be transported in minute quantities, even as a powder that can be dusted on paper. It is lethal if burned and even a spoonful can cause immediate extreme irritation of the eyes and breathing passages. A chemical like chloroform ascitone methanol can be transported on filter paper, then combined with a heat source to create an explosion.

CONVENTIONAL WEAPONRY

Intelligence and military analysts have repeatedly warned that extremists in Iraq, the tribal areas of Pakistan and elsewhere are currently developing a high level of military skill and experience. This reality underscores the need for nuclear plants to be able to defend against attackers utilizing the full range of potential weaponry that terrorists are known to be capable of using, including heavy caliber automatic weapons; sniper rifles; shoulder-fired rockets; mortars; platter charges; anti-tank weaponry; bunker busters; shaped charges; rocket-propelled grenades; and high-power explosives.

Numerous weapons systems posing a threat to even the best trained and equipped civilian guard force, as well as to on-site installations, are readily available and easy to transport. To wit:

o Assault rifles and other rapid-fire battlefield weapons such as AK-47's, Uzi's and TEC-9's are freely available in the U.S. A weapon like the SKS 7.62-millimenter semiautomatic assault rifle can be purchased for under $200. In 2005 the Government Accountability Office reported that 47 individuals on a federal terrorism watch list were actually permitted to legally buy guns in 2004.

o A standard M-24 sniper rifle with day and night scope can be carried in a canvas bag and fires 7.62-millimeter ammunition targeting up to 3000 feet

o A .50-caliber Barrett rifle, which can be purchased for $1000 on the internet, weighs a mere 30 lbs and can hit targets up to 6000 feet away with armor-piercing bullets that can blow a hole through a concrete bunker, bring down a helicopter or pierce an armored vehicle.

o A rocket propelled grenade launcher is re-loadable, can fire at the speed of 400 feet per second and can blow a vehicle into the air.

o A TOW missile is an accessible form of military hardware used in over 40 countries and can be fired from a launcher on a flatbed truck. A 1998 test TOW fired into a nuclear waste transport cask (which is more robust than many on-site nuclear waste storage casks) blew out a hole the size of a grapefruit. The Kornet-E missile, developed by the Soviets and sold to Iraq, can travel over 3 miles and cut through over 3 feet of steel. The world's arms market is awash in thousands of Milan missiles. The 60-70 lb Milan missile system has an effective range of over 5000 feet and can blow a hole through more than 3 feet of armor plate.

o The deployment of increasingly powerful and sophisticated explosives, including shaped charges and explosively formed penetrators (or E.F.P.s) by terrorists and insurgents in Iraq show that the explosives use capabilities of enemies of the United States should not be underestimated. Notably, the 18 men arrested in Australia in November 2005, and believed to have been planning an attack on an Australian nuclear reactor, had allegedly been stockpiling materials used to make the explosive triacetone triperoxide, or TATP. Terrorists targeting a U.S. nuclear power plant may very well be able to draw on expertise developed during the Iraq insurgency as well as military experts and rocket scientists from the former Iraq government or from hostile nations such as Iran. In addition, the strategic utility of explosives is magnified when bombers are willing to blow themselves up. Suicide bombers able to gain access to the internal areas of a nuclear power plant during the course of an attack could cause untold destruction.

o Perhaps the most intractable military hardware threat is posed by shoulder-fired missiles such as

Stingers, SA-7's, SA-14's and SA-18's. An estimated 500,000 such systems are scattered throughout the world and have been found in the possession of at least 27 terrorist or guerrilla groups. Some can be bought easily on the black market for as little as several thousand dollars each. Critically, shoulder-fired missiles are easy to operate (Al Qaeda training videos offer instruction) and are designed for portability, typically being 5-6 feet long and weighing 35 lbs. They can be transported by and fired from a van, S.U.V., pickup truck or recreational boat. Even a single terrorist armed with a shoulder-fired missile can cause immediate and substantial damage to a targeted structure. Traveling at more than 1,500 miles per hour, a typical shoulder-launched missile has a range of over 12,000 feet. If the target remains intact following the initial strike, the terrorist can attach a new missile tube to the grip stock launcher and fire again.

WATERBORN ATTACKS

Waterborne defenses of nuclear plants adjacent to navigable waterways must be significantly enhanced. Facilities must either be engineered to withstand damage from a waterborne attack or suited with physical barriers that prevent entry to the plant and/or critical cooling intake equipment.

Continual cooling is an essential component of nuclear plant safety. A meltdown can be triggered even at a scrammed reactor if cooling is obstructed. Water intake is also essential to the proper function of spent fuel pools. Yet at certain nuclear plants, cooling systems may be highly vulnerable. At both Indian Point and Millstone Power Station, in particular, water intake pipes have been identified by engineering experts as exposed and susceptible to waterborne sabotage.

One or more boats laden with high energy explosives could severely compromise cooling water intakes easily and quickly. Indian Point, for instance, is located on the banks of the Hudson River in an area heavily trafficked by commercial and recreational vessels. The 900 foot "Exclusion Zone" -marked only by buoys- could be traversed by speed boats in 30 - 40 seconds, well before any Coast Guard or other patrol boat could react. Patrol boats could also be readily taken out by suicide bomber boats crashing into them (in the manner a small explosives laden boat targeted the destroyer the USS Cole in 2000) or by weaponry like shoulder-fired missiles or rocket propelled grenades.

AERIAL ASSAULT

According to a terrorist "threat matrix" issued by the National Research Council and the National Academies of Sciences and Engineering following the September 2001 attack, "Nuclear power plants may present a tempting high-visibility target for terrorist attack, and the potential for a September 11-type surprise attack in the near term using U.S. assets such as airplanes appears to be high."

In March 2005, a joint FBI and Department of Homeland Security assessment stated that commercial airlines are "likely to remain a target and a platform for terrorists" and that "the largely unregulated" area of general aviation (which includes corporate jets, private airplanes, cargo planes, and chartered flights) remains especially vulnerable. The assessment further noted that Al Qaeda has "considered the use of helicopters as an alternative to recruiting operatives for fixed-wing operations," adding that the maneuverability and "non-threatening appearance" of helicopters, even when flying at low altitudes, makes them "attractive targets for use during suicide attacks or as a medium for the spraying of toxins on targets below."

The vulnerability of nuclear power plants to malevolent airborne attack is detailed extensively in the Petition filed by the National Whistleblower Center and Randy Robarge in 2002 pursuant to 10 CFR Sec. 2.206. A number of studies of the issue are also reviewed in Appendix A to these Comments. The particular vulnerability of nuclear spent fuel pools to this kind of attack is detailed in the January 2003 report of Dr. Gordon Thompson, director of the Institute for Resource and Security Studies entitled "Robust Storage of Spent Nuclear Fuel: A Neglected Issue of Homeland Security" and in the findings of a multi-institution team study led by Frank N. Von Hippel, a physicist and co-director of the Program on Science and Global Security at Princeton University and published in the spring 2003 edition of the Princeton journal *Science and Global Security* under the title "Reducing the Hazards from Stored Spent Power-Reactor Fuel in the United States." It is worthy of note that, even post-9/11, general aviation aircraft have circled or flown closely over commercial nuclear facilities without military interception.

The NRC's sole present strategy for averting a kamikaze attack upon a nuclear power plant is reliance upon aviation security upgrades implemented by the Transportation Security Administration and the Federal Aviation Administration and faith that U.S. intelligence will provide ample warning.

It is this kind of governmental agency pass-the-buck mindset that brought the nation Katrina.

The NRC's conjecture also betrays a reality disconnect reminiscent of the federal response to Katrina. Since 2001 there have been numerous breaches of airport security throughout the nation. Notably, in late 2005, there were three serious security breaches at Newark International Airport, one of the points of departure used by the September 11 hijackers. The most serious occurred on November 12, 2005, when a man driving a large S.U.V. barreled through the armed security checkpoint and drove in a secured area for 45 minutes before being found by NY/NJ Port Authority officers. Just this year, gaping holes in airport security were exposed when workers with access to secure areas were able to carry firearms in their carry-on bags onto a commercial jet departing from Florida.

The PRSR must furthermore be upgraded to include high-speed attack by a jumbo jet of the maximum size anticipated to be in commercial use (such as the expanded version of the Boeing 747 and the Airbus A380) as well as unexpected attack by general aviation aircraft and helicopters. The PRSR must contemplate all such aircraft to be fully loaded, fueled and armed with explosives.

It is essential that the PRSR address not only the direct effect of impact, but the full potential aftereffects of (A) induced vibrations; (B) dislodged debris falling onto sensitive equipment; (C) a fuel fire; and (D) the combustion of aerosolized fuel (especially in combination with pre-existing on-site gases such as hydrogen).

The PRSR must further take into consideration the cascading consequences of aerial assault on the full spectrum of plant installations. Inarguably, there is a wide range of on-site structures, not within hardened containment, that are critical to the safe operation of a nuclear plant. Spent fuel pools are of particular concern because the disposition of water could uncover the fuel. If plant workers are unable to effectuate replacement of the water (either because of fire or because they are otherwise incapacitated), experts warn, an exothermic reaction could cause the zirconium clad spent fuel rods to ignite a nuclear waste conflagration that would very likely spew the entire radioactive contents of the spent fuel pool into the atmosphere.

Without question, hardening a nuclear power plant against aerial threat will necessitate significant upgrades in plant fortification. However even relatively modest measures such as the installation of Beamhenge and the placement of all sufficiently cooled spent fuel into Hardened On-Site Storage Systems (known as H.O.S.S.) would add measurable protection.

STRATEGIC USES OF RIGS, TRUCKS AND S.U.V.'S

In June 1991, the NRC denied the truck bomb petition of the Committee to Bridge the Gap and the Nuclear Information Resource Service, on the grounds that it was not realistic to believe a truck bomb would be employed in the U.S. Two years later, on February 26, 1993, terrorists drove a rented van packed with explosives into the underground garage of the World Trade Center, lighted a fuse and fled. Just a couple of weeks before that, a mentally unstable individual crashed his station wagon through the gates of the protected area of the Three Mile Island nuclear power station and evaded security for several hours before finally wrecking his vehicle by crashing into the turbine building. Thereafter, the NRC reconsidered its earlier assessment and has, on a number of occasions, upgraded reactor security standard to include some protections against land vehicles. Such upgrades, however, are insufficient in a post-9/11 world.

Large Sport Utility Vehicles and pickup trucks on the road today can weigh over 8 tons, loaded, and -as do commercial vans- have considerably carrying capacity. Such vehicles could be used strategically in a number of ways.

The first is as a mobile short range projectile bomb. A large, heavy vehicle packed with high explosives, even if not successful in penetrating concrete barriers, could result in the death or incapacitation of large

numbers of plant workers, including security, personnel. Such casualties would be particularly likely to materialize if the vehicle bomb followed a previous diversionary event intended to draw security personnel to the plant perimeter.

The second is as a transport vehicle for one team of attackers who are themselves armed or who wear explosive belts and could then themselves penetrate other areas of the facility. A terrorist wearing an explosive body belt can, in effect, be a precision guided weapon.

The third and fourth scenarios are variations of the first two, with chemical agents substituted for or combined with explosives. (Indeed, insurgents in Iraq are increasingly combining explosives with chlorine gas and other chemical payloads in truck bomb detonations.) One or two such vehicles packed with the right toxins, could be expected to kill or disable a substantial number of workers, again, especially if the release followed a prior event which drew security personnel to the area, or simply to areas outside facility enclosures. Certain toxins can be lethal to anyone within miles. Using such agents, attackers wearing protective gear could then gain access to other areas of the facility.

A fifth tactical use of vehicles would not even occur on site. Vehicles carrying explosives and/or chemical agents could be set off at critical regional transportation arteries such as major bridges, tunnels and highways. Notably, such incidents could be staged in a way that would not even alert authorities to the onset of terrorist activity. In the New York metropolitan region in which Indian Point is sited, for example, a series of major accidents occurring at or about the same time would not be an unusual occurrence. In fact, on July 25, 2003, the very day the Federal Emergency Management Agency declared that the Indian Point emergency plan provided "adequate" assurance of protection to the public, the entire New York metropolitan region was brought to a virtual traffic standstill after a tractor-trailer hit a beam on the George Washington Bridge and burst into flames, several minor accidents and a car fire took place on Interstate 95, and a truck got jammed under an overpass of the Hutchinson River Parkway. In 2006, a tanker truck carrying 8000 gallons of gasoline overturned on one of New York City's busiest highways, igniting a blaze that burned for hours and weakening the steel beams of an above bridge. Earlier this month a liquid propane explosion closed a 23 mile stretch of the New York State Thruway for hours, while firefighters had to stand by and watch the fire burn out because it was too hot to approach.

The staging of a couple of incidents like those just noted, combined with an "accident" involving a tanker carrying hazardous gasses or liquids like liquefied ammonia, propane, chlorine, or vinyl chloride, prior to an assault would almost assuredly forestall the provision of outside assistance to a nuclear facility under attack.

PLANTS MUST BE ABLE TO MOUNT A FULL DEFENSE WITHOUT RELIANCE ON OUTSIDE ASSISTANCE

Whether or not an attack employs strategies designed to obstruct regional transportation routes, numerous studies and the actual events of 9/11, Katrina, and Rita (as well as relatively minor events such as the January 18, 2006 wind storm in NY) demonstrate beyond cavil that first responder forces and the National Guard do not have the resources, manpower, equipment or communications capabilities to swiftly and adequately respond to a major assault on a nuclear facility. Just this very month, a report of the Commission on the National Guard and Reserves detailed the ongoing problem of inadequate human, equipment, communications and financial resources plaguing the National Guard. This report calls into question the ability of the government to bring all necessary assets to bear in the immediate aftermath of a major domestic incident.

In some regions - most notably the New York Metropolitan region, in which Indian Point is sited - roadway logistics and regular congestion alone would likely prevent assisting forces from reaching a nuclear plant under attack in time. It bears mention that SWAT team assembly takes approximately 2 hours, whereas an assault could be over in a matter of minutes.

It is accordingly crucial that the NRC cedes the faulty assumption that plant personnel need only fend off attackers until law enforcement or military aid arrives. The fact that most regional first responders have little detailed knowledge of either the operational or internal layout of nuclear facilities further testifies to the folly of reliance upon the "cavalry".

ELEVATED VULNERABILITY TO INFILTRATION DURING EVENT

During a crisis event at a nuclear plant there also exists an elevated threat of infiltration by terrorists posing as first responders or National Guard. And in fact the imposter tactic has been used by terrorists in recent years with substantial success.

Terrorists disguised as firefighters could take particularly strong advantage of this stratagem. Outside firefighters often respond to fires at nuclear power plants and many attack scenarios would be expected to involve fire. Firefighters would presumptively be seen as benign by plant personnel and would have a legitimate reason to move throughout a facility and "check" components such as electrical wiring. Moreover, bulky firefighter uniforms and equipment can hold and hide a host of articles that could be used for destructive purposes.

DEFENSE AGAINST A SIZABLE MULTI-TEAM, MULTI-DIRECTIONAL FORCE

In January 1991, the Nuclear Information Resource Service and the Committee to Bridge the Gap filed a joint Petition with the NRC requesting, *inter alia,* that the DBT be upgraded to 20 external attackers. The NRC rejected the petition in June 1991, asserting that an attack involving more than 3 assailants was unrealistic.

September 11 was a demonstration of the profound limitations of governmental foresight.

The September 11 plot involved 20 attackers (although only 19 were ultimately able to participate). The tragic 2004 siege at a school in Belsan, Russia involved more than 30 armed terrorists. It should be beyond question at this point that a terrorist attack could involve scores of attackers.

Accordingly, the PRSR must assume at least two dozen attackers. Lessons learned from 9/11 and the many multiple coordinated terrorist actions that have transpired in Europe, Asia and the Middle East since then, also mandate the premise that attackers will act in several teams and that some of those teams may be sizable.

Any carefully planned attack on a nuclear facility by knowledgeable individuals, would also involve several different *modus operandi.* The PRSR should therefore take into account the consequences of near-simultaneous damage to different plant installations, systems and personnel (e.g., the effect of a small explosive-laden plane diving into the roof of a spent fuel pool coupled with the waterborne sabotage of the spent fuel pool intake system).

A COORDINATED ATTACK ON MULTIPLE ON AND OFF-SITE TARGETS

A related point is that, following 9/11, the NRC can no longer ignore the very real possibility that an attack on a nuclear power plant would occur commensurate with an attack on other regional infrastructure such as chemical plants and bridges. A coordinated attack designed to effectively eradicate a region would very likely preliminarily target communication, electrical power and/or transportation infrastructures. This would ensure that (A) the targeted region is reduced to mass confusion, (B) local and federal officials and responders would be overwhelmed, and (C) law enforcement and other first responders would be impeded from gaining access to the nuclear plant site.

Certain areas of the U.S. offer a plethora of target opportunities and thus are particularly vulnerable to multiple target scenarios. Prime among them is the greater New York Metropolitan area (already in the terrorists' crosshairs) which contains numerous national landmarks, corporate headquarters, reservoirs, bridges, airports, transportation arteries and hazardous chemical plants, all in near vicinity to Indian Point, a mere 24 miles north of New York City.

A CREDIBLE NUCLEAR PLANT SECURITY FORCE TESTING PROGRAM

The deficiencies, failures, and chicanery that have long plagued the various manifestations of nuclear

power industry security drills and force-on-force (FOF) testing have been exhaustively documented in recent years. Noteworthy investigations in this regard have been conducted by the Project on Government Oversight (augmented by testimony provided in 2002 Senate Environment and Public Works Committee hearings) and the United States General Accounting Office (which reported its findings in a September 2003 report entitled "Oversight of Security at Commercial Nuclear Power Plants Needs to Be Strengthened") as well as by the press. Problems with the FOF program are also addressed in the July 2004 Petition for Rulemaking to amend 10 CFR Part 73 to upgrade the DBT filed by the Committee to Bridge the Gap and the Comments on the DBT filed in 2006 by the Union of Concerned Scientists. CIECP fully endorses the recommendations made in previous filings by the Committee to Bridge the Gap and the Union of Concerned Scientists.

CIECP urges the NRC in the strongest possible terms to upgrade drills and testing protocols to remedy the flaws that are a matter of public record and to take into account the realities noted herein. FOF tests must be sufficiently challenging to provide high confidence in the defensive capabilities of the security forces at the nation's 103 nuclear power plants. One clear failing of the FOF program to date has been the giving of excessive warning regarding upcoming tests. While some notice is necessary, one week should suffice. In addition, staff assignments should be frozen on the day of notice. This would eliminate the all too common practice of substituting a plant's most fit and accomplished security personnel in place of underachievers.

It is also critical that drills and the FOF program be revamped to eliminate manifest conflicts of interest. Examples of blatant conflicts of interest include: (1) The NRC allowing the nuclear industry's lobbying arm, the Nuclear Energy Institute (NEI) to award a FOF contract; and (2) The NEI, with NRC approval, then selecting Wackenhut, a corporation which contracts security guards to nuclear power plants in the U.S., to also be the contractor that supplies the mock adversary teams for the FOF tests.

Such problems have reduced the value of testing to the point where the FOF program lacks public confidence. The program must be redesigned and monitored by an independent entity such as the very capable U.S. military.

HIGH TARGET APPEAL REACTORS

Prior terrorist attacks and plots against the U.S. have focused on major cities. It is a matter of fundamental logic that plants sited in highly populated metropolitan areas, particularly those with high symbolic value, face the greatest risk of being selected as a target.

It is thus imperative that the PRSR be modified to mandate a customized approach to high target nuclear facilities.

SITE-SPECIFIC SAFETY-RELATED VULNERABILITIES

It is highly unrealistic to exclude from the PRSR calculus the reality of aging structures, deteriorated conditions and compromised systems that exist at various nuclear power plants in the U.S. A facility-customized approach must be taken which adds problems which are known or reasonably suspected and which could have a significant effect upon the ability of plant operators to maintain control during a major incident into the security equation.

Prime among factors which may be site-specific are:

o Corrosion and Embrittlement: For example, a risk of corrosion of the steel liner of the reactor containment at the Oyster Creek Nuclear Generating Station (Oyster Creek) was recently identified. A qualified corrosion expert has warned that the risk may be high enough to cause buckling and collapse. Manifestly, corrosion or embrittlement-weakened structures and components are more vulnerable to the effects of heat and combustion.

o Vulnerability to Fire: Fire detection and suppression equipment and fire barriers are crucial to reactor safety. Over 20 years ago a worker at the Brown's Ferry Unit 1 reactor accidentally started a fire which destroyed emergency cooling systems and severely compromised the plant's ability to monitor its

condition. In response, the NRC increased fire safety standards. In recent years, the NRC has effectively relaxed those standards. This is exceedingly unwise. During the chaos and threat level that would surely exist during a terrorist attack, human beings cannot be presumed to be able to take the actions necessary to protect critical systems from fire. The systems themselves must have integral safeguards. Yet plants such as Arkansas Nuclear One, Catawba, Ginna, H.B. Robinson, Indian Point, James A. Fitzpatrick, McGuire, Shearon Harris, Vermont Yankee and Waterford have been identified as having fire barrier wrap systems that failed fire tests. Fireproofing problems such as these jeopardize safe shutdown and must be recognized as a degradation of defense-in-depth protection. In addition, any plant fire hazard analyses must assume damage to multiple rooms and multiple structures, a circumstance that could easily result from an aircraft impact.

o Integrity of Structures that Support Mobility: While the focus of NRC regulatory review is on structures and equipment directly related to safe operational function, the conditions that may prevail during an assault would likely require plant personnel to be able to move rapidly throughout the facility. The evaluation of the reliability of structural features such as stairways (which might buckle or melt during a fire) is accordingly critical.

o Electrical System Problems: In 2003, a cable failure knocked out power to approximately half the safety systems at Oyster Creek, including security cameras, alarms, sensors, pumps and valves. In February 2003, all 4 of the backup generators at Fermi became simultaneously inoperable. In December 2001, Indian Point reactor 2 lost power due to a malfunction of the turbine, then lost back-up power to the reactor coolant system because of a second electrical failure. During the August 2003 blackout that struck the Northeast, following the loss of off-site power, two of Indian Point's emergency backup generators (both of which had been previously flagged as having problems) failed to operate. In view of the severe consequences failures such as these could have were they to occur during a major incident, known plant electrical system vulnerabilities must be taken into consideration.

o Cooling System Problems: Cooling system problems and design deficiencies have plagued a number of plants in recent years. In some cases the NRC has allowed plants to operate for long periods with compromised emergency cooling systems. For example, the Salem nuclear power station had experienced two years of repeated malfunctions of its high-pressure coolant-injection system prior to the time, in October 2003, when operators unsuccessfully tried to use it to stabilize water levels following a steam pipe burst. And the NRC has allowed reactors with emergency sump pumps flagged as likely to become clogged and inoperative to remain in operation for many years without repair. The Los Alamos National Laboratory, for instance, concluded that the sump pumps at Indian Point reactors 2 and 3 could become clogged in as little as 23 minutes and 14 minutes, respectively. While, upgrades are being made, the failure of the NRC to mandate immediate correction of cooling system vulnerabilities calls its oversight capabilities seriously into question. Indeed the functional declination of critical systems must be deemed a constituent element of site-specific PRSR analyses.

ELIMINATE COMMERCIAL CONSIDERATIONS FROM THE PRSR CALCULUS

The commercial interests of the nuclear industry are of valid concern to nuclear utilities and the NEI; they should not be of concern to the NRC. There is no justification for jeopardizing national security and the health and safety of the public - even to the smallest degree - to safeguard corporate profits.

The NRC has stated that its promulgated security standards are based upon the analysis of the largest threat against which a "**private security force could reasonably be expected to defend**" [*emphasis added*] 70 FR 67385.

Both the NRC and the industry have acknowledged that, in their estimation, a private guard force should not be reasonably expected to defend against a 9/11-type attack involving aircraft. Such an attack, apparently, is deemed to fall under the loophole of 10 CFR Sec. 50.13, which exempts reactor operators from defending against "an enemy of the United States, a foreign government or other person". The perimeter of this "enemy of the United States provision has never been defined, so there is no way to know how far it extends. However, it is abundantly clear from the public record that the NRC has drawn the line at point where the profit margins of nuclear power operators might be significantly affected. Unfortunately, the terrorists are constrained by no such boundary.

Congress has charged the NRC with the obligation to protect the public health and safety. This must not be viewed simply as a guideline; it must be viewed as an uncompromised mandate.

If the NRC does not believe its licensees can afford the security upgrades necessary to protect the nation's nuclear reactors against the full potential threat, it must act with forthrightness and publicly demand that the Department of Homeland Security or the U.S. military assume responsibility for domestic nuclear power plant security.

CONCLUSION

The 9/11 Commission observed: "Across the government, there were failures of imagination, policy, capabilities...The most important failure was one of imagination. We do not believe leaders understood the gravity of the threat."

As a public interest group we ask: What needs to happen before the gravity of the threat is not only understood, but acted upon?

Respectfully submitted,

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APPENDIX A

Since September 11, 2001, there has been much speculation about the vulnerability of nuclear power plants to aerial attack. Certainty, however, is in short supply.

What is known is that none of the nuclear reactors presently operational in the United States were built to withstand the crash of a jumbo jet, much less the crash of super jumbo such as the A380 which will take to the air weighing 1.2 million pounds, has a wingspan almost as long as a football field, is 8 stories tall, and is 3 times as large as the 767s that brought down the Twin Towers.

Nevertheless studies that have addressed the prospect of planes hitting nuclear plants include the following:

1974: To date the only published peer reviewed study on the vulnerability of U.S. nuclear power plants was conducted by General Electric, the leading builder of nuclear plants, and published in the industry journal *Nuclear Safety*. GE looked at accidents -not terror attacks - and concluded that were a "heavy" airliner to hit a reactor building in the right place, it would almost certainly rip it apart. Such a hit would also most likely damage the reactor core and both the cooling and emergency cooling systems. [NOTE: The GE study defined a "heavy" plane as one weighing more than 6 tons. The Boeing 757 which gouged a 100 foot gash through the reinforced concrete of the Pentagon weighed between 80 and 100 tons. A fully loaded 767 weighs over 200 tons. The Airbus 380, expected to be launched into commercial use later this year, takes to the air weighing 1.2 million pounds, hundreds of thousands of pounds heavier

than the Boeing 747, the current jumbo of the sky.]

1982: A technical report (previously publicly available) of a study conducted by the U.S. Army Corps of Engineers at the NRC's behest focused on plane crash analyses at the Argonne National Laboratory. The Corps concluded that planes traveling at a speed of over 466 mph would crash through the average reactor containment structure noting "account has been taken of the internal concrete wall which acts as a missile barrier...It would appear, however, that this is too optimistic since vaporized fuel, hot gaseous reaction products, and to a certain extent portions of liquid fuel streams will flow around such obstructions and overwhelm internal defenses...." [NOTE: An FBI analysis estimated that American Airlines Flight 11, which hit the north tower of the World Trade Center, was traveling at a speed of 494 mph, and that United Airlines Flight 175, which hit the south tower, was traveling at 586 mph, a speed far exceeding its design limit for the altitude.]

2000: A NRC study published less than a year before September 11 calculated that 1 out 2 commercial airplanes flying in the year 2000 were large enough to penetrate even a 5 foot thick reinforced concrete wall 45% of the time. Specifically, the study states, "aircraft damage can affect the structural integrity of the spent fuel pool or the availability of nearby support systems, such as power supplies, heat exchangers, or water makeup sources and may also affect recovery actions...It is estimated that half the commercial aircraft now flying are large enough to penetrate the 5 foot thick reinforced concrete walls." [NOTE: The thickness of the top of certain reactor domes is 3 and-a-half feet.]

2002: The German Reactor Safety Organization (GRS) a scientific-technical research group that works primarily for nuclear regulators in Germany conducted an extremely detailed study that determined that terrorists can, with a strategically targeted airplane crash, initiate a nuclear accident. (A secret Ministry document that summarized the report was leaked to the German and Austrian press and subsequently translated into English.) The GRS study used dynamic computation modeling that looked at the potential consequences of a wide range of impact possibilities on different plant equipment and installations. Different types of airplanes, velocities, angles of impact, weight loads and fuel effects were considered, as were various sequences of events. Aside from the basic finding of vulnerability, the GRS study is significant for recognizing the limitations of even its highly complex analyses. Key unknowns include the impacts of fire loads on many kind of materials and equipment as well as the behaviors of various combustive materials under the conditions of a plane crash.

2004: In 2004 the U.K. Parliamentary Office of Science and Technology (OST) issued a secret report on the risks of terrorist attacks on nuclear facilities to the U.K. House of Commons Defense Committee. The OST report was leaked to the magazine *New Scientist*, which reported the OST conclusion that a large plane crash into a nuclear reactor could release as much radiation as the1986 accident at Chernobyl, while a crash into the nuclear waste tanks at the U.K.'s Sellafield facility could cause several million fatalities.

From these studies it is clear that there exists a reasonable basis for concern regarding malevolent deployment of aircraft against nuclear power facilities.

It should also be evident that all studies on this topic are, in substance, educated conjecture. The current state of computer modeling is not up to analyzing the full range of physical and chemical interactions that could occur under the incalculable range of different kinds of aircraft, approaching at different angles, at different speeds, hitting different structures, which all have facility-unique room and equipment layouts, and different substance, chemical, and ventilation-related conditions.

A lesson in the unpredictable consequences of airplane crashes was brought home on September 11 (when even the 47 story tall 7 World Trade Center that was not struck collapsed for reasons engineers have yet to fully determine). A lesson in the limitations of advanced computer modeling can also be learned from the Columbia space shuttle disaster.

[~DBT and PRSR]

EXHIBIT HH

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

---x

In re:

License Renewal Application Submitted by

Entergy Nuclear Indian Point 2, LLC,
Entergy Nuclear Indian Point 3, LLC, and
Entergy Nuclear Operations, Inc.

---x

Docket Nos. 50-247-LR and 50-286-LR

ASLBP No. 07-858-03-LR-BD01

DPR-26, DPR-64

NEW YORK STATE
NOTICE OF INTENTION TO PARTICIPATE
AND PETITION TO INTERVENE

Filed on November 30, 2007

EXHIBIT WW

Report to Congressional Requesters:

May 2004:

Nuclear Regulation:

NRC's Liability Insurance Requirements for Nuclear Power Plants Owned by Limited Liability Companies:

[Hyperlink, http://www.gao.gov/cgi-bin/getrpt?GAO-04-654]:

GAO Highlights:

Highlights of GAO-04-654, a report to congressional requesters

Why GAO Did This Study:

An accident at one the nation's commercial nuclear power plants could result in human health and environmental damages. To ensure that funds would be available to settle liability claims in such cases, the Price-Anderson Act requires licensees for these plants to have primary insurance—currently $300 million per site. The act also requires secondary coverage in the form of retrospective premiums to be contributed by all licensees to cover claims that exceed primary insurance. If these premiums are needed, each licensee's payments are limited to $10 million per year and $95.8 million in total for each of its plants. In recent years, limited liability companies have increasingly become licensees of nuclear power plants, raising concerns about whether these companies—by shielding their parent corporations' assets—will have the financial resources to pay their retrospective premiums.

GAO was asked to determine (1) the extent to which limited liability

companies are the licensees for U.S. commercial nuclear power plants, (2) the Nuclear Regulatory Commission's (NRC) requirements and procedures for ensuring that licensees of nuclear power plants comply with the Price-Anderson Act's liability requirements, and (3) whether and how these procedures differ for licensees that are limited liability companies.

What GAO Found:

Of the 103 operating nuclear power plants, 31 are owned by 11 limited liability companies. Three energy corporations—Exelon, Entergy, and the Constellation Energy Group—are the parent companies for eight of these limited liability companies. These 8 subsidiaries are the licensees or co-licensees for 27 of the 31 plants.

NRC requires all licensees for nuclear power plants to show proof that they have the primary and secondary insurance coverage mandated by the Price-Anderson Act. Licensees obtain their primary insurance through American Nuclear Insurers. Licensees also sign an agreement with NRC to keep the insurance in effect. American Nuclear Insurers also has a contractual agreement with each of the licensees to collect the retrospective premiums if these payments become necessary. A certified copy of this agreement, which is called a bond for payment of retrospective premiums, is provided to NRC as proof of secondary insurance. It obligates the licensee to pay the retrospective premiums to American Nuclear Insurers.

NRC does not treat limited liability companies differently than other licensees with respect to the Price-Anderson Act's insurance requirements. Like other licensees, limited liability companies must show proof of both primary and secondary insurance coverage. American Nuclear Insurers also requires limited liability companies to provide a letter of guarantee from their parent or other affiliated companies with sufficient assets to pay the retrospective premiums. These letters state that the parent or affiliated companies are responsible for paying the retrospective premiums if the limited liability company does not. American Nuclear Insurers informs NRC it has received these letters. In light of the increasing number of plants owned by limited liability companies, NRC is studying its existing regulations and expects to report on its findings by the end of summer 2004.

In commenting on a draft of this report, NRC stated that it accurately reflects the present insurance system for nuclear power plants.

www.gao.gov/cgi-bin/getrpt?GAO-04-654.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Jim Wells at 202-512-3841.

[End of section]

Contents:

Letter May 28, 2004:

Congressional Requesters:

An accident at one of the nation's 103[Footnote 1] operating commercial nuclear power plants could result in human health and environmental damages. The Price-Anderson Act was enacted in 1957 to ensure that funds would be available for at least a portion of the damages suffered by the public in the event of an incident at a U.S. nuclear power plant. The act requires each licensee of a nuclear plant to have primary insurance coverage equal to the maximum amount of liability insurance available from private sources--currently $300 million--to settle any such claims against it. In the event of an accident at any plant where liability claims exceed the $300 million primary insurance coverage, the act also requires licensees for all plants to pay retrospective premiums (also referred to as secondary insurance). Under current U.S. Nuclear Regulatory Commission (NRC) regulations, these payments could amount to a maximum of $95.8 million for each of a licensee's plants per incident. If claims for an incident exceed this approximately $10 billion currently available in primary insurance and retrospective premiums, NRC may request additional funds from the Congress. To operate a nuclear power plant, the owner must obtain a license from NRC and meet its regulatory requirements, including those for liability insurance established under the Price-Anderson Act.

A major aspect of the deregulation or restructuring of the U.S. electricity industry in the 1990s was the separation of electricity generation from transmission and distribution. Utilities could create separate entities or subsidiaries to operate their generation facilities, including nuclear power plants, or could sell them off to other companies. Energy holding companies bought some of the generation facilities, sometimes placing them under subsidiaries. The limited liability company also emerged in the 1990s as a new type of company structure in the United States. These companies have characteristics of both a partnership and a corporation. Like a partnership, the profits

are passed through and taxable to the owners, known as members; like a corporation, it is a separate and distinct legal entity and its owners are insulated from personal liability for its debts and liabilities.

You asked us to determine (1) the extent to which limited liability companies are the licensees for U.S. commercial nuclear power plants, (2) NRC's requirements and procedures for ensuring that licensees of nuclear power plants comply with the Price-Anderson Act's liability requirements, and (3) whether and how these procedures differ for licensees that are limited liability companies. To respond to your request, we reviewed applicable sections of the Price-Anderson Act and NRC's implementing regulations and written procedures. We also held discussions with and obtained information from responsible NRC officials and representatives of American Nuclear Insurers, which is a joint underwriting association of 50 insurance companies that provides insurance coverage to the nuclear power plants. These are property/ casualty insurance companies licensed to do business in at least one of the states or territories of the United States. We performed our work between April 2003 and April 2004 in accordance with generally accepted government auditing standards.

Results in Brief:

Thirty-one of the 103 operating commercial nuclear power plants nationwide are licensed to limited liability companies. Four of the 31 plants are licensed jointly to two limited liability companies. A total of 11 limited liability companies are licensed to own nuclear power plants. One--the Exelon Generation Company, LLC--is the licensee for 12 plants and co-licensee for 4 plants. The 10 other limited liability companies are the licensees or co-licensees for one to five plants. Three energy corporations--Exelon, Entergy, and the Constellation Energy Group--are the parent companies for eight of the limited liability companies. These eight subsidiaries are the licensees or co-licensees for 27 of the 31 plants.

NRC's procedures for ensuring that licensees comply with Price-Anderson Act liability insurance provisions include requirements that licensees provide proof of primary and secondary insurance coverage. NRC requires each licensee to show proof that it has liability insurance that includes the $300 million of primary insurance coverage per site required by the Price-Anderson Act. NRC and the licensee also sign an indemnity agreement that requires the licensee to maintain an insurance policy in this amount. This agreement is in effect as long as the owner is licensed to operate the plant. NRC relies on American Nuclear Insurers--the joint underwriting association that provides insurance for U.S. nuclear power plants--to send NRC the annual endorsements documenting proof of insurance after the licensees have paid their annual premiums. In addition to the primary insurance coverage, licensees must also show proof of secondary insurance to NRC. This secondary insurance is in the form of retrospective premiums that, in the event of a nuclear incident causing damages exceeding $300 million, would be collected from each nuclear power plant licensee at a rate of up to $10 million per year and up to a maximum of $95.8 million per incident for each nuclear power plant. Typically, each licensee signs a bond for payment of retrospective premiums as proof of the secondary insurance and furnishes NRC with a certified copy. This bond is a contractual agreement between the licensee and American Nuclear Insurers that obligates the licensee to pay American Nuclear Insurers the retrospective premiums. In the event that claims exhaust primary coverage, American Nuclear Insurers would collect the retrospective

premiums. If a licensee did not pay its share of these retrospective premiums, American Nuclear Insurers would, under its agreement with the licensees, pay up to $30 million of the premiums in 1 year and attempt to collect this amount later from the licensees.

NRC does not treat limited liability companies differently than other licensees of nuclear power plants with respect to Price-Anderson Act liability requirements. All licensees follow the same regulations and procedures regardless of whether they are limited liability companies. Like other licensees, limited liability companies are required to show that they are maintaining $300 million in primary insurance coverage, and they provide NRC a copy of the bond for payment of retrospective premiums. While NRC does not conduct in-depth financial reviews specifically to determine licensees' ability to pay retrospective premiums, when a licensee applies for a license or when the license is transferred, NRC reviews the licensee's financial ability to safely operate the plant and to contribute decommissioning funds for the future retirement of the plant. According to NRC officials, if licensees have the financial resources to cover these two expenses, they are likely to be capable of paying their retrospective premiums. American Nuclear Insurers goes further than NRC and requires limited liability companies to provide a letter of guarantee from their parent or other affiliated companies with sufficient assets to cover the retrospective premiums. These letters state that the parent or an affiliated company is responsible for paying the retrospective premiums if the limited liability company does not. American Nuclear Insurers informs NRC that it has received these letters of guarantee. Recognizing that limited liability companies are becoming more prevalent as owners of nuclear power plants, NRC is examining whether it needs to revise any of its regulations and procedures for these companies. NRC estimates the study will be completed by the end of summer 2004.

In commenting on a draft of this report, NRC stated that it accurately reflects the present insurance system for nuclear power plants.

Background:

The Atomic Energy Act of 1954 authorized a comprehensive regulatory program to permit private industry to develop and apply atomic energy for peaceful uses, such as generating electricity from privately owned nuclear power plants. Soon thereafter, government and industry experts identified a major impediment to accomplishing the act's objective: the potential for payment of damages resulting from a nuclear accident and the lack of adequate available insurance. Unwilling to risk huge financial liability, private companies viewed even the remote specter of a serious accident as a roadblock to their participating in the development and use of nuclear power.[Footnote 2] In addition, congressional concern developed over ensuring adequate financial protection to the public because the public had no assurance that it would receive compensation for personal injury or property damages from the liable party in event of a serious accident. Faced with these concerns, the Congress enacted the Price-Anderson Act in September 1957. The Price-Anderson Act has two underlying objectives: (1) to establish a mechanism for compensating the public for personal injury or property damage in the event of a nuclear accident and (2) to encourage the development of nuclear power.

To provide financial protection, the Price-Anderson Act requires commercial nuclear reactors to be insured to the maximum level of

primary insurance available from private insurers. To implement this provision, NRC periodically revises its regulations to require licensees of nuclear reactors to increase their coverage level as the private insurance market increases the maximum level of primary insurance that it is willing to offer. For example, in January 2003, NRC increased the required coverage from $200 million to the current $300 million, when American Nuclear Insurers informed NRC that $300 million per site in coverage was now available in its insurance pool.

In 1975, the Price-Anderson Act was amended to require licensees to pay a pro-rated share of the damages in excess of the primary insurance amount. Under this amendment, each licensee would pay up to $5 million in retrospective premiums per facility it owned per incident if a nuclear accident resulted in damages exceeding the amount of primary insurance coverage. In 1988, the act was further amended to increase the maximum retrospective premium to $63 million per reactor per incident to be adjusted by NRC for inflation. The amendment also limited the maximum annual retrospective premium per reactor to $10 million. Under the act, NRC is to adjust the maximum amount of retrospective premiums every 5 years using the aggregate change in the Consumer Price Index for urban consumers. In August 2003, NRC set the current maximum retrospective payment at $95.8 million per reactor per incident. With 103 operating nuclear power plants, this secondary insurance pool would total about $10 billion.[Footnote 3]

The Price-Anderson Act also provides a process to deal with incidents in which the damages exceed the primary and secondary insurance coverage. Under the act, NRC shall survey the causes and extent of the damage and submit a report on the results to, among others, the Congress and the courts. The courts must determine whether public liability exceeds the liability limits available in the primary insurance and secondary retrospective premiums. Then the President would submit to the Congress an estimate of the financial extent of damages, recommendations for additional sources of funds, and one or more compensation plans for full and prompt compensation for all valid claims. In addition, NRC can request the Congress to appropriate funds. The most serious incident at a U.S. nuclear power plant took place in 1979 at the Three Mile Island Nuclear Station in Pennsylvania. That incident has resulted in $70 million in liability claims.

NRC's regulatory activities include licensing nuclear reactors and overseeing their safe operation. Licensees must meet NRC regulations to obtain and retain their license to operate a nuclear facility. NRC carries out reviews of financial qualifications of reactor licensees when they apply for a license or if the license is transferred, including requiring applicants to demonstrate that they possess or have reasonable assurance of obtaining funds necessary to cover estimated operating costs for the period of the license. NRC does not systematically review its licensees' financial qualifications once it has issued the license unless it has reason to believe this is necessary. In addition, NRC performs inspections to verify that a licensee's activities are properly conducted to ensure safe operations in accordance with NRC's regulations. NRC can issue sanctions to licensees who violate its regulations. These sanctions include notices of violation; civil penalties of up to $100,000 per violation per day; and orders that may modify, suspend, or revoke a license.

Limited Liability Companies Are Licensees for 31 of the 103 Operating Commercial Nuclear Power Plants in the United States:

Thirty-one commercial nuclear power plants nationwide are licensed to limited liability companies. In total, 11 limited liability companies are licensed to own nuclear power plants. Three energy corporations--Exelon, Entergy, and the Constellation Energy Group--are the parent companies for 8 of these limited liability companies. These eight subsidiaries are licensed or co-licensed to operate 27 of the 31 plants. The two subsidiaries of the Exelon Corporation are the licensees for 15 plants and the co-licensees for 4 others. Constellation Energy Group, Inc., and Entergy Corporation are the parent companies of limited liability companies that are licensees for four nuclear power plants each. (See table 1.):

Table 1: Limited Liability Companies Licensed to Operate Nuclear Power Plants and Their Parent Companies:

Limited liability company: Exelon Generation Company, LLC;
Parent company: Exelon Corporation;
Number of plants owned or co-owned: 12.

Limited liability company: AmerGen Energy Company, LLC;
Parent company: Exelon Corporation;
Number of plants owned or co-owned: 3.

Limited liability company: Exelon Generation Company, LLC; PSEG Nuclear, LLC;
Parent company: Exelon Corporation; Public Service Enterprise Group, Incorporated;
Number of plants owned or co-owned: 4.

Limited liability company: PSEG Nuclear, LLC;
Parent company: Public Service Enterprise Group, Incorporated;
Number of plants owned or co-owned: 1.

Limited liability company: Calvert Cliffs Nuclear Power Plant, LLC;
Parent company: Constellation Energy Group, Inc.;
Number of plants owned or co-owned: 2.

Limited liability company: Nine Mile Point Nuclear Station, LLC;
Parent company: Constellation Energy Group, Inc.;
Number of plants owned or co-owned: 2.

Limited liability company: Entergy Nuclear Indian Point 2, LLC;
Parent company: Entergy Corporation;
Number of plants owned or co-owned: 1.

Limited liability company: Entergy Nuclear Indian Point 3, LLC;
Parent company: Entergy Corporation;
Number of plants owned or co-owned: 1.

Limited liability company: Entergy Nuclear FitzPatrick, LLC;
Parent company: Entergy Corporation;
Number of plants owned or co-owned: 1.

Limited liability company: Entergy Nuclear Vermont Yankee, LLC;
Parent company: Entergy Corporation;
Number of plants owned or co-owned: 1.

Limited liability company: FPL Energy Seabrook, LLC;
Parent company: FPL Group, Inc.;
Number of plants owned or co-owned: 1.

Limited liability company: PPL Susquehanna, LLC;
Parent company: Pennsylvania Power and Light Company;
Number of plants owned or co-owned: 2.

Source: GAO survey of NRC project managers.

[End of table]

Of all the limited liability companies, Exelon Generation Company, LLC, has the largest number of plants. It is the licensee for 12 plants and co-licensee with PSEG Nuclear, LLC, for 4 other plants. For these 4 plants, Exelon Generation owns 43 percent of Salem Nuclear Generating Stations 1 and 2 and 50 percent of Peach Bottom Atomic Power Stations 2 and 3. (App. I lists all the licensees and their nuclear power plants.):

NRC Has Specific Requirements and Procedures to Ensure That All Licensees Comply with the Price-Anderson Act's Liability Provisions:

NRC requires licensees of nuclear power plants to comply with the Price-Anderson Act's liability insurance provisions by maintaining the necessary primary and secondary insurance coverage. First, NRC ensures that licensees comply with the primary insurance coverage requirement by requiring them to submit proof of coverage in the amount of $300 million. Second, NRC ensures compliance with the requirement for secondary coverage by accepting the certified copy of the licensee's bond for payment of retrospective premiums.

All the nuclear power plant licensees purchase their primary insurance from American Nuclear Insurers. American Nuclear Insurers sends NRC annual endorsements documenting proof of primary insurance after the licensees have paid their annual premiums. NRC and each licensee also sign an indemnity agreement, stating that the licensee will maintain an insurance policy in the required amount. This agreement, which is in effect as long as the owner is licensed to operate the plant, guarantees reimbursement of liability claims against the licensee in the event of a nuclear incident through the liability insurance. The agency can suspend or revoke the license if a licensee does not maintain the insurance, but according to an NRC official, no licensee has ever failed to pay its annual primary insurance premium and American Nuclear Insurers would notify NRC if a licensee failed to pay.[Footnote 4]

As proof of their secondary insurance coverage, licensees must provide evidence that they are maintaining a guarantee of payment of retrospective premiums. Under NRC regulations, the licensee must provide NRC with evidence that it maintains one of the following six types of guarantees: (1) surety bond, (2) letter of credit, (3) revolving credit/term loan arrangement, (4) maintenance of escrow deposits of government securities, (5) annual certified financial statement showing either that a cash flow can be generated and would be available for payment of retrospective premiums within 3 months after submission of the statement or a cash reserve or combination of these, or (6) such other type of guarantee as may be approved by the Commission.

Before the late 1990s, the licensees provided financial statements to NRC as evidence of their ability to pay retrospective premiums.[Footnote 5] According to NRC officials, in the late 1990s,

Entergy asked NRC to accept the bond for payment of retrospective premiums that it had with American Nuclear Insurers as complying with the sixth option under NRC's regulations: such other type of guarantee as may be approved by the Commission. After reviewing and agreeing to Entergy's request, NRC decided to accept the bond from all the licensees as meeting NRC's requirements. NRC officials told us that they did not document this decision with Commission papers or incorporate it into the regulations because they did not view this as necessary under the regulations.

The bond for payment of retrospective premiums is a contractual agreement between the licensee and American Nuclear Insurers that obligates the licensee to pay American Nuclear Insurers the retrospective premiums. Each licensee signs this bond and furnishes NRC with a certified copy. In the event that claims exhaust primary coverage, American Nuclear Insurers would collect the retrospective premiums. If a licensee were not to pay its share of these retrospective premiums, American Nuclear Insurers would, under its agreement with the licensees, pay for up to three defaults or up to $30 million in 1 year of the premiums and attempt to collect this amount later from the defaulting licensees. According to an American Nuclear Insurers official, any additional defaults would reduce the amount available for retrospective payments. An American Nuclear Insurers official told us that his organization believes that the bond for payment of retrospective premiums is legally binding and obligates the licensee to pay the premium. Under NRC regulations, if a licensee fails to pay the assessed deferred premium, NRC reserves the right to pay those premiums on behalf of the licensee and recover the amount of such premiums from the licensee.

NRC Treats Limited Liability Companies the Same as Other Licensees, but the Insurance Industry Has Added Important Requirements for These Companies:

NRC applies the same rules to limited liability companies that it does to other licensees of nuclear power plants with respect to liability requirements under the Price-Anderson Act.

All licensees must meet the same requirements regardless of whether they are limited liability companies. American Nuclear Insurers applies an additional requirement for limited liability companies with respect to secondary insurance coverage in order to ensure that they have sufficient assets to pay retrospective premiums. Given the growing number of nuclear power plants licensed to limited liability companies, NRC is examining the need to revise its procedures and regulations for such companies.

NRC requires all licensees of nuclear power plants to follow the same regulations and procedures. Limited liability companies, like other licensees, are required to show that they are maintaining the $300 million in primary insurance coverage and provide NRC a copy of the bond for payment of retrospective premiums or other approved evidence of guarantee of retrospective premium payments. According to NRC officials, all its licensees, including those that are limited liability companies, have sufficient assets to cover the retrospective premiums. While NRC does not conduct in-depth financial reviews specifically to determine licensees' ability to pay retrospective premiums, it reviews the licensees' financial ability to safely operate their plants and to contribute decommissioning funds for the future retirement of the plants. According to NRC officials, if licensees have

the financial resources to cover these two larger expenses, they are likely to be capable of paying their retrospective premiums.

American Nuclear Insurers goes further than NRC and requires licensees that are limited liability companies to provide a letter of guarantee from their parent or other affiliated companies with sufficient assets to cover the retrospective premiums. An American Nuclear Insurers official stated that American Nuclear Insurers obtains these letters as a matter of good business practice. These letters state that the parent or an affiliated company is responsible for paying the retrospective premiums if the limited liability company does not. If the parent company or other affiliated company of a limited liability company does not provide a letter of guarantee, American Nuclear Insurers could refuse to issue the bond for payment of retrospective premiums and the company would have to have another means to show NRC proof of secondary insurance. American Nuclear Insurers informs NRC that it has received these letters of guarantee. The official also told us that American Nuclear Insurers believes that the letters from the parent companies or other affiliated companies of the limited liability company licensed by NRC are valid and legally enforceable contracts.

NRC officials told us that they were not aware of any problems caused by limited liability companies owning nuclear power plants and that NRC currently does not regard limited liability companies' ownership of nuclear power plants as a concern. However, because these companies are becoming more prevalent as owners of nuclear power plants, NRC is examining whether it needs to revise any of its regulations or procedures for these licensees. NRC estimates that it will complete its study by the end of summer 2004.

Agency Comments:

We provided a draft of this report to NRC for review and comment. In its written comments (see app. II), NRC stated that it believes the report accurately reflects the present insurance system for nuclear power plants. NRC said that we correctly conclude that the agency does not treat limited liability companies differently than other licensees with respect to Price-Anderson's insurance requirements. NRC also stated that we are correct in noting that it is not aware of any problems caused by limited liability companies owning nuclear power plants and that NRC currently does not regard limited liability companies' ownership of nuclear power plants as a concern. In addition, NRC commented that we agree with the agency's conclusion that all its reactor licensees have sufficient assets that they are likely to be able to pay the retrospective premiums. With respect to this last comment, the report does not take a position on the licensees' ability to pay the retrospective premiums. We did not evaluate the sufficiency of the individual licensees' assets to make these payments. Instead, we reviewed NRC's and the American Nuclear Insurers' requirements and procedures for retrospective premiums.

Scope and Methodology:

We performed our review at NRC headquarters in Washington, D.C. We reviewed statutes, regulations, and appropriate guidance as well as interviewed agency officials to determine the relevant statutory framework of the Price-Anderson Act. To determine the number of nuclear power plant licensees that are limited liability companies, we surveyed, through electronic mail, all the NRC project managers responsible for maintaining nuclear power plant licenses. We asked them

to provide data on the licensees, including the licensee's name and whether it was a limited liability company. If it was a limited liability company, we asked when the license was transferred to the limited liability company and who is the parent company of the limited liability company. We received responses for all 103 nuclear power plants currently licensed to operate. We analyzed the results of the survey responses. We verified the reliability of the data from a random sample of project managers by requesting copies of the power plant licenses and then comparing the power plant licenses to the data provided by the project managers. The data agreed in all cases. We concluded that the data were reliable enough for the purposes of this report.

To determine NRC's requirements for ensuring that licensees of nuclear power plants comply with the Price-Anderson Act's liability requirements, we reviewed relevant statutes and NRC regulations and interviewed NRC officials responsible for ensuring that licensees have primary and secondary insurance coverage. We also spoke with American Nuclear Insurers officials responsible for issuing the insurance coverage to nuclear power plant licensees, and we reviewed relevant documents associated with the insurance. To determine whether and how these procedures differ for licensees that are limited liability companies, we reviewed relevant documents, including NRC regulations, and interviewed NRC officials responsible for ensuring licensee compliance with Price-Anderson Act requirements.

As agreed with your offices, unless you publicly announce its contents earlier, we plan no further distribution of this report until 7 days from the date of this letter. We will then send copies to interested congressional committees; the Commissioners, Nuclear Regulatory Commission; the Director, Office of Management and Budget; and other interested parties. We will make copies available to others on request. In addition, the report will be available at no charge on GAO's Web site at [Hyperlink, http://www.gao.gov].

If you or your staff have any questions about this report, I can be reached at (202) 512-3841. Major contributors to this report include Ray Smith, Ilene Pollack, and Amy Webbink. John Delicath and Judy Pagano also contributed to this report.

Signed by:

Jim Wells,
Director, Natural Resources and Environment:

List of Congressional Requesters:

The Honorable Hillary Rodham Clinton:
The Honorable James M. Jeffords:
The Honorable Harry Reid:
United States Senate:

[End of section]

Appendixes:

Appendix I: Nuclear Power Plant Ownership:

1;
Plant: Arkansas Nuclear One 1;

Licensed to own: Entergy Arkansas, Inc.;
LLC: No.

2;
Plant: Arkansas Nuclear One 2;
Licensed to own: Entergy Arkansas, Inc.;
LLC: No.

3;
Plant: Arnold (Duane) Energy Center;
Licensed to own: Interstate Power and Light;
LLC: No;
Licensed to own: Central Iowa Power Cooperative;
LLC: No;
Licensed to own: Corn Belt Power Cooperative;
LLC: No.

4;
Plant: Beaver Valley Power Station 1;
Licensed to own: Pennsylvania Power Company;
LLC: No.
Licensed to own: Ohio Edison Company;
LLC: No;
Licensed to own: FirstEnergy Nuclear Operating Company;
LLC: No.

5;
Plant: Beaver Valley Power Station 2;
Licensed to own: Pennsylvania Power Company;
LLC: No;
Licensed to own: Ohio Edison Company;
LLC: No;
Licensed to own: Cleveland Electric Illuminating Company;
LLC: No;
Licensed to own: Toledo Edison Company;
LLC: No;
Licensed to own: FirstEnergy Nuclear Operating Company;
LLC: No.

6;
Plant: Braidwood Station 1;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

7;
Plant: Braidwood Station 2;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

8;
Plant: Browns Ferry Nuclear Power Station 1;
Licensed to own: Tennessee Valley Authority;
LLC: No.

9;
Plant: Browns Ferry Nuclear Power Station 2;

Licensed to own: Tennessee Valley Authority;
LLC: No.

10;
Plant: Browns Ferry Nuclear Power Station 3;
Licensed to own: Tennessee Valley Authority;
LLC: No.

11;
Plant: Brunswick Steam Electric Plant 1;
Licensed to own: Carolina Power & Light Co.;
LLC: No;
Licensed to own: North Carolina Eastern Municipal Power Agency;
LLC: No.

12;
Plant: Brunswick Steam Electric Plant 2;
Licensed to own: Carolina Power & Light Co.;
LLC: No;
Licensed to own: North Carolina Eastern Municipal Power Agency;
LLC: No.

13;
Plant: Byron Station 1;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

14;
Plant: Byron Station 2;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

15;
Plant: Callaway Plant;
Licensed to own: Union Electric Company;
LLC: No.

16;
Plant: Calvert Cliffs Nuclear Power Plant 1;
Licensed to own: Calvert Cliffs Nuclear Power Plant, LLC;
LLC: Yes;
License transfer date: 6/19/2001;
LLC parent company: Constellation Energy Group, Inc..

17;
Plant: Calvert Cliffs Nuclear Power Plant 2;
Licensed to own: Calvert Cliffs Nuclear Power Plant, LLC;
LLC: Yes;
License transfer date: 6/19/2001;
LLC parent company: Constellation Energy Group, Inc..

18;
Plant: Catawba Nuclear Station 1;
Licensed to own: North Carolina Electric Membership Corp.;
LLC: No;
Licensed to own: Saluda River Electric Cooperative, Inc.;

LLC: No;
Licensed to own: Duke Energy Corporation;
LLC: No.

19;
Plant: Catawba Nuclear Station 2;
Licensed to own: North Carolina Municipal Power Agency No. 1;
LLC: No;
Licensed to own: Piedmont Municipal Power Agency;
LLC: No.

20;
Plant: Clinton Power Station;
Licensed to own: AmerGen Energy Company, LLC;
LLC: Yes;
License transfer date: 11/24/1999;
LLC parent company: Exelon Corporation.

21;
Plant: Columbia Generation Station;
Licensed to own: Energy Northwest;
LLC: No.

22;
Plant: Comanche Peak Steam Electric Station 1;
Licensed to own: TXU Generation Company LP;
LLC: No.

23;
Plant: Comanche Peak Steam Electric Station 2;
Licensed to own: TXU Generation Company LP;
LLC: No.

24;
Plant: Cook (Donald C.) Nuclear Power Plant 1;
Licensed to own: Indiana Michigan Power Company;
LLC: No.

25;
Plant: Cook (Donald C.) Nuclear Power Plant 2;
Licensed to own: Indiana Michigan Power Company;
LLC: No.

26;
Plant: Cooper Nuclear Station;
Licensed to own: Nebraska Public Power District;
LLC: No.

27;
Plant: Crystal River Nuclear Plant 3;
Licensed to own: Florida Power Corporation;
LLC: No;
Licensed to own: City of Alachua;
LLC: No;
Licensed to own: City of Bushnell;
LLC: No;
Licensed to own: City of Gainesville;
LLC: No;
Licensed to own: City of Kissimmee;
LLC: No;

Licensed to own: City of Leesburg;
LLC: No;
Licensed to own: City of New Smyrna Beach and Utilities Commission;
LLC: No;
Licensed to own: City of Ocala;
LLC: No;
Licensed to own: Orlando Utilities Commission and City of Orlando;
LLC: No;
Licensed to own: Seminole Electric Cooperative, Inc.;
LLC: No.

28;
Plant: Davis-Besse Nuclear Power Station;
Licensed to own: Cleveland Electric Illumination Company;
LLC: No;
Licensed to own: Toledo Edison Company;
LLC: No.

29;
Plant: Diablo Canyon Nuclear Power Plant 1;
Licensed to own: Pacific Gas and Electric Company;
LLC: No.

30;
Plant: Diablo Canyon Nuclear Power Plant 2;
Licensed to own: Pacific Gas and Electric Company;
LLC: No.

31;
Plant: Dresden Nuclear Power Station 2;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 8/3/2000;
LLC parent company: Exelon Corporation.

32;
Plant: Dresden Nuclear Power Station 3;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 8/3/2000;
LLC parent company: Exelon Corporation.

33;
Plant: Farley (Joseph M.) Nuclear Plant 1;
Licensed to own: Alabama Power Company;
LLC: No.

34;
Plant: Farley (Joseph M.) Nuclear Plant 2;
Licensed to own: Alabama Power Company;
LLC: No.

35;
Plant: Fermi (Enrico) Atomic Power Plant 2;
Licensed to own: Detroit Edison Company;
LLC: No.

36;
Plant: FitzPatrick (James A.) Nuclear Power Plant;
Licensed to own: Entergy Nuclear FitzPatrick, LLC;

LLC: Yes;
License transfer date: 11/ 21/2000;
LLC parent company: Entergy Corporation.

37;
Plant: Fort Calhoun Station;
Licensed to own: Omaha Public Power District;
LLC: No.

38;
Plant: Ginna (Robert E.) Nuclear Station;
Licensed to own: Rochester Gas and Electric Corporation;
LLC: No.

39;
Plant: Grand Gulf Nuclear Station;
Licensed to own: System Energy Resources, Inc.;
LLC: No;
Licensed to own: South Mississippi Electric Power Assoc.;
LLC: No.

40;
Plant: Harris (Shearon) Nuclear Power Plant;
Licensed to own: Carolina Power & Light Co.;
LLC: No;
Licensed to own: North Carolina Eastern Municipal Power Agency;
LLC: No.

41;
Plant: Hatch (Edwin I.) Nuclear Plant 1;
Licensed to own: Georgia Power Company;
LLC: No;
Licensed to own: Municipal Electric Authority of Georgia;
LLC: No;
Licensed to own: Oglethorpe Power Corporation;
LLC: No;
Licensed to own: City of Dalton, Georgia;
LLC: No.

42;
Plant: Hatch (Edwin I.) Nuclear Plant 2;
Licensed to own: Georgia Power Company;
LLC: No;
Licensed to own: Municipal Electric Authority of Georgia;
LLC: No;
Licensed to own: Oglethorpe Power Corporation;
LLC: No;
Licensed to own: City of Dalton, Georgia;
LLC: No.

43;
Plant: Hope Creek Nuclear Power Station;
Licensed to own: PSEG Nuclear, LLC;
LLC: Yes;
License transfer date: 8/21/2000;
10/18/2001;
LLC parent company: Public Service Enterprise Group, Incorporated.

44;
Plant: Indian Point 2;

Licensed to own: Entergy Nuclear Indian Point 2, LLC;
LLC: Yes;
License transfer date: 9/6/2001;
LLC parent company: Entergy Corporation.

45;
Plant: Indian Point 3;
Licensed to own: Entergy Nuclear Indian Point 3, LLC;
LLC: Yes;
License transfer date: 11/21/2000;
LLC parent company: Entergy Corporation.

46;
Plant: Kewaunee Nuclear Power Plant;
Licensed to own: Wisconsin Public Service Corp.;
LLC: No;
Licensed to own: Wisconsin Power & Light Company;
LLC: No.

47;
Plant: LaSalle County Station 1;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

48;
Plant: LaSalle County Station 2;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

49;
Plant: Limerick Generating Station 1;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

50;
Plant: Limerick Generating Station 2;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

51;
Plant: McGuire (William B.) Nuclear Station 1;
Licensed to own: Duke Energy Corporation;
LLC: No.

52;
Plant: McGuire (William B.) Nuclear Station 2;
Licensed to own: Duke Energy Corporation;
LLC: No.

53;
Plant: Millstone Nuclear Power Station 2;
Licensed to own: Dominion Nuclear Connecticut, Inc.;

LLC: No.

54;
Plant: Millstone Nuclear Power Station 3;
Licensed to own: Dominion Nuclear Connecticut, Inc.;
LLC: No;
Licensed to own: Central Vermont Public Service Corporation;
LLC: No;
Licensed to own: Massachusetts Municipal Wholesale Electric Co.;
LLC: No.

55;
Plant: Monticello Nuclear Generating Plant;
Licensed to own: Northern States Power Company;
LLC: No.

56;
Plant: Nine Mile Point Nuclear Station 1;
Licensed to own: Nine Mile Point Nuclear Station, LLC;
LLC: Yes;
License transfer date: 11/7/ 2001;
LLC parent company: Constellation Energy Group.

57;
Plant: Nine Mile Point Nuclear Station 2;
Licensed to own: Nine Mile Point Nuclear Station, LLC;
LLC: Yes;
License transfer date: 11/7/ 2001;
LLC parent company: Constellation Energy Group;
Licensed to own: Long Island Lighting Company;
LLC: No.

58;
Plant: North Anna Power Station 1;
Licensed to own: Virginia Electric and Power Company;
LLC: No;
Licensed to own: Old Dominion Electric Cooperative;
LLC: No.

59;
Plant: North Anna Power Station 2;
Licensed to own: Virginia Electric and Power Company;
LLC: No;
Licensed to own: Old Dominion Electric Cooperative;
LLC: No.

60;
Plant: Oconee Nuclear Station 1;
Licensed to own: Duke Energy Corporation;
LLC: No.

61;
Plant: Oconee Nuclear Station 2;
Licensed to own: Duke Energy Corporation;
LLC: No.

62;
Plant: Oconee Nuclear Station 3;
Licensed to own: Duke Energy Corporation;
LLC: No.

63;
Plant: Oyster Creek Nuclear Power Plant;
Licensed to own: AmerGen Energy Company, LLC;
LLC: Yes;
License transfer date: 8/8/2000;
LLC parent company: Exelon Corporation.

64;
Plant: Palisades Nuclear Plant;
Licensed to own: Consumers Energy Company;
LLC: No.

65;
Plant: Palo Verde Nuclear Generating Station 1;
Licensed to own: Arizona Public Service Company;
LLC: No;
Licensed to own: Salt River Project Agricultural Improvement and Power District;
LLC: No;
Licensed to own: El Paso Electric Company;
LLC: No;
Licensed to own: Southern California Edison Company;
LLC: No;
Licensed to own: Public Service Company of New Mexico;
LLC: No;
Licensed to own: Los Angeles Dept. of Water and Power;
LLC: No;
Licensed to own: Southern California Public Power Authority;
LLC: No.

66;
Plant: Palo Verde Nuclear Generating Station 2;
Licensed to own: Arizona Public Service Company;
LLC: No;
Licensed to own: Salt River Project Agricultural Improvement and Power District;
LLC: No;
Licensed to own: El Paso Electric Company;
LLC: No;
Licensed to own: Southern California Edison Company;
LLC: No;
Licensed to own: Public Service Company of New Mexico;
LLC: No;
Licensed to own: Los Angeles Dept. of Water and Power;
LLC: No;
Licensed to own: Southern California Public Power Authority;
LLC: No.

67;
Plant: Palo Verde Nuclear Generating Station 3;
Licensed to own: Arizona Public Service Company;
LLC: No;
Licensed to own: Salt River Project Agricultural Improvement and Power District;
LLC: No;
Licensed to own: El Paso Electric Company;
LLC: No;
Licensed to own: Southern California Edison Company;
LLC: No;

Licensed to own: Public Service Company of New Mexico;
LLC: No;
Licensed to own: Los Angeles Dept. of Water and Power;
LLC: No;
Licensed to own: Southern California Public Power Authority;
LLC: No.

68;
Plant: Peach Bottom Atomic Power Station 2;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation;
Licensed to own: PSEG Nuclear, LLC;
LLC: Yes.

LLC parent company: Public Service Enterprise Group, Incorporated.

69;
Plant: Peach Bottom Atomic Power Station 3;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation;
Licensed to own: PSEG Nuclear, LLC;
LLC: Yes.

LLC parent company: Public Service Enterprise Group, Incorporated.

70;
Plant: Perry Nuclear Power Plant;
Licensed to own: Ohio Edison Company;
LLC: No;
Licensed to own: Cleveland Electric Company;
LLC: No;
Licensed to own: Toledo Edison Company;
LLC: No.

71;
Plant: Pilgrim Station;
Licensed to own: Entergy Nuclear Generation Co.;
LLC: No.

72;
Plant: Point Beach Nuclear Plant 1;
Licensed to own: Wisconsin Electric Power Company;
LLC: No.

73;
Plant: Point Beach Nuclear Plant 2;
Licensed to own: Wisconsin Electric Power Company;
LLC: No.

74;
Plant: Praire Island Nuclear Plant 1;
Licensed to own: Northern States Power Company;
LLC: No.

75;
Plant: Praire Island Nuclear Plant 2;

Licensed to own: Northern States Power Company;
LLC: No.

76;
Plant: Quad Cities Station 1;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 8/3/2000;
LLC parent company: Exelon Corporation;
Licensed to own: 77: MidAmerican Energy Company;
LLC: 77: No;
License transfer date: 77: [Empty];
LLC parent company: 77: [Empty].

77;
Plant: Quad Cities Station 2;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 8/3/2000;
LLC parent company: Exelon Corporation;
Licensed to own: MidAmerican Energy Company;
LLC: No.

78;
Plant: River Bend Station;
Licensed to own: Entergy Gulf States, Inc.;
LLC: No.

79;
Plant: Robinson (H. B.) Plant 2;
Licensed to own: Carolina Power & Light Co.;
LLC: No.

80;
Plant: Salem Nuclear Generating Station 1;
Licensed to own: PSEG Nuclear, LLC;
LLC: Yes;
License transfer date: 8/21/2000;
LLC parent company: Public Service Enterprise Group, Incorporated;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

81;
Plant: Salem Nuclear Generating Station 2;
Licensed to own: PSEG Nuclear, LLC;
LLC: Yes;
License transfer date: 8/21/2000;
LLC parent company: Public Service Enterprise Group, Incorporated;
Licensed to own: Exelon Generation Company, LLC;
LLC: Yes;
License transfer date: 1/12/2001;
LLC parent company: Exelon Corporation.

82;
Plant: San Onofre Nuclear Generating Station 2;
Licensed to own: Southern California Edison Company;
LLC: No.

83;
Plant: San Onofre Nuclear Generating Station 3;
Licensed to own: Southern California Edison Company;
LLC: No.

84;
Plant: Seabrook Nuclear Power Station;
Licensed to own: FPL Energy Seabrook, LLC;
LLC: Yes;
License transfer date: 11/1/2002;
LLC parent company: FPL Group, Inc.;
Licensed to own: Massachusetts Municipal Wholesale Electric Co.;
LLC: No;
Licensed to own: Tauton Municipal Lighting Plant;
LLC: No;
Licensed to own: Hudson Light & Power Department;
LLC: No.

85;
Plant: Sequoya Nuclear Plant 1;
Licensed to own: Tennessee Valley Authority;
LLC: No.

86;
Plant: Sequoya Nuclear Plant 2;
Licensed to own: Tennessee Valley Authority;
LLC: No.

87;
Plant: South Texas Project 1;
Licensed to own: Texas Genco, LP;
LLC: No;
Licensed to own: City Public Service Board of San Antonio;
LLC: No;
Licensed to own: Central Power & Light Company;
LLC: No;
Licensed to own: City of Austin, Texas;
LLC: No.

88;
Plant: South Texas Project 2;
Licensed to own: Texas Genco, LP;
LLC: No;
Licensed to own: City Public Service Board of San Antonio;
LLC: No;
Licensed to own: Central Power & Light Company;
LLC: No;
Licensed to own: City of Austin, Texas;
LLC: No.

89;
Plant: St. Lucie Plant 1;
Licensed to own: Florida Power and Light Company;
LLC: No.

90;
Plant: St. Lucie Plant 2;
Licensed to own: Florida Power and Light Company;
LLC: No;
Licensed to own: Florida Municipal Power Agency;

LLC: No;
Licensed to own: Orlando Utilities Commission;
LLC: No.

91;
Plant: Summer (Virgil C.) Nuclear Station;
Licensed to own: South Carolina Electric & Gas Company;
LLC: No;
Licensed to own: South Carolina Public Service Authority;
LLC: No.

92;
Plant: Surry Power Station 1;
Licensed to own: Virginia Electric and Power Company;
LLC: No.

93;
Plant: Surry Power Station 2;
Licensed to own: Virginia Electric and Power Company;
LLC: No.

94;
Plant: Susquehanna Steam Electric Station 1;
Licensed to own: PPL Susquehanna, LLC;
LLC: Yes;
License transfer date: 6/1/2000;
LLC parent company: Pennsylvania Power and Light Company.

95;
Plant: Susquehanna Steam Electric Station 2;
Licensed to own: PPL Susquehanna, LLC;
LLC: Yes;
License transfer date: 6/1/2000;
LLC parent company: Pennsylvania Power and Light Company.

96;
Plant: Three Mile Island Nuclear Station 1;
Licensed to own: AmerGen Energy Company, LLC;
LLC: Yes;
License transfer date: 12/20/ 1999;
LLC parent company: Exelon Corporation.

97;
Plant: Turkey Point Station 3;
Licensed to own: Florida Power and Light Company;
LLC: No.

98;
Plant: Turkey Point Station 4;
Licensed to own: Florida Power and Light Company;
LLC: No.

99;
Plant: Vermont Yankee Nuclear Power Station;
Licensed to own: Entergy Nuclear Vermont Yankee, LLC;
LLC: Yes;
License transfer date: 7/1/2002;
LLC parent company: Entergy Corporation;
Licensed to own: Entergy Nuclear Operations, Inc.;
LLC: No.

100;
Plant: Vogtle (Alvin W.) Nuclear Plant 1;
Licensed to own: Georgia Power Company;
LLC: No;
Licensed to own: Municipal Electric Authority of Georgia;
LLC: No;
Licensed to own: Oglethorpe Power Corporation;
LLC: No;
Licensed to own: City of Dalton, Georgia;
LLC: No.

101;
Plant: Vogtle (Alvin W.) Nuclear Plant 2;
Licensed to own: Georgia Power Company;
LLC: No;
Licensed to own: Municipal Electric Authority of Georgia;
LLC: No;
Licensed to own: Oglethorpe Power Corporation;
LLC: No;
Licensed to own: City of Dalton, Georgia;
LLC: No.

102;
Plant: Waterford Generating Station 3;
Licensed to own: Entergy Operations, Inc.;
LLC: No.

103;
Plant: Watts Bar Nuclear Plant 1;
Licensed to own: Tennessee Valley Authority;
LLC: No.

104;
Plant: Wolf Creek Generating Station;
Licensed to own: Kansas Gas & Electric Company;
LLC: No;
Licensed to own: Kansas City Power & Light Company;
LLC: No;
Licensed to own: Kansas Electric Power Cooperative, Inc.;
LLC: No.

Source: GAO survey of NRC Project Managers.

[End of table]

[End of section]

Appendix II: Comments from the Nuclear Regulatory Commission:

UNITED STATES NUCLEAR REGULATORY COMMISSION:
WASHINGTON, D.C. 20555-0001:

April 29, 2004:

Mr. James E. Wells:

Director, Natural Resources and Environment:
United States General Accounting Office:
441 G Street, N.W.

Washington, DC 20548:

Dear Mr. Wells:

I would like to thank you for the opportunity to review and submit comments on the May 2004 draft of the General Accounting Office's (GAO) report entitled "Nuclear Regulation-NBC's Liability Insurance Requirements for Nuclear Power Plants Owned by Limited Liability Companies." The U.S. Nuclear Regulatory Commission (NRC) appreciates the time and effort that you and your staff have taken to review this topic.

GAO correctly concludes that NRC does not treat limited liability companies differently than other licensees with respect to the Price-Anderson's insurance requirements. Like other licensees, limited liability companies must show proof of both primary and secondary financial protection. GAO also is correct in noting that NRC is not aware of any problems caused by limited liability companies owning nuclear power plants and that NRC currently does not regard limited liability companies' ownership of nuclear power plants as a concern. Finally, GAO agrees with NBC's conclusion that all its reactor licensees have sufficient assets that they are likely to be able to pay the retrospective premiums. These assets are assured by a number of different methods that are approved by NRC as GAO discusses in its report.

The NRC believes that the GAO report accurately reflects the present insurance system for nuclear power plants. Therefore, we do not have any comments to provide regarding the draft report.

Sincerely,

Signed by:

William D. Travers:
Executive Director for Operations:

cc: Ilene Pollack, GAO:

(360330):

FOOTNOTES

[1] Although 104 commercial nuclear power plants are licensed to operate in the United States, 1 plant, Browns Ferry Unit 1, was shut down in 1985 and remains idle.

[2] NRC's regulations define a nuclear incident as any occurrence that causes bodily injury, sickness, disease, or death or loss of or damage to property or for loss of the use of property arising out of or resulting from the radioactive, toxic, explosive, or other hazardous properties of the source, special nuclear or byproduct material.

[3] NRC regulations also require licensees to maintain $1 billion in on-site property damage insurance to provide funds to deal with cleanup of the reactor site after an accident.

[4] The average annual premium for a single nuclear power plant at a site is about $400,000. The premium for a second or third plant at the same site is discounted because the maximum amount of primary insurance

for a multi-plant site is $300 million.

[5] Fifteen licensees continue to provide financial statements to NRC.

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EXHIBIT XX

EXHIBIT XX

Replacing the Electricity Generated at Indian Point – Westchester Citizen's Awareness Network – White Paper November 5, 2007

The Indian Point Energy Center is located on a prime piece of commercially zoned, river front property. This valuable piece of property is an asset to the community no matter what it is used for or who owns it. Property taxes, or a renegotiated payment in lieu of taxes, will regularly fall due regardless of whether the nuclear reactors are operating or not. Taxes from Indian Point contribute less than 1% to Westchester County's budget. Nonetheless county officials have voted unanimously for plant closure. In the town of Buchanan a much higher percentage of the budget is from the PILOT negotiated by Entergy. Initially a reduction in the PILOT could adversely affect the tax rates, job security and economic activity. There is time for elected officials to plan ahead and address these concerns in a business like fashion before the current operating license expires. However, this is immaterial to the re-licensing process. It is the responsibility of elected officials to come to some reasonable and just social policy in regard to these matters as has been done in the past when businesses throughout Westchester have relocated or gone bankrupt. Energy policy and the health and safety of 21 million people cannot be held hostage to 750 jobs at Entergy and resultant economic activity. After decommissioning is completed, it is unlikely that the property will sit idle. It has excellent access to the regional electric grid and gas supply lines in one of the most densely populated areas of the country. Many uses, including alternative methods for generation of electricity, are possible. This possibility was noted in the Levitan study when they reported that alternative on site generation had the potential to avoid or mitigate the costs and impacts of closure of Indian Point. There is time for elected officials to plan ahead and address these concerns in a business like fashion before the current operating license expires.

Contribution of Indian Point to Westchester and New York City

The percentage of electricity contributed by Indian Point to the metropolitan area has frequently been misstated. It is important to have an accurate figure for future planning. The figures below clarify the contributions from both Indian Point 2 and 3. They provide an accurate picture of how to figure the capacity of the plant as a percentage for the region.

The combined output from Indian Point 2 and 3 of 2,000 MW represents 11 percent of the total generating capacity for New York City and Westchester. On a typical day when both plants are operating normally this is is approximately 16% percent of the energy delivered in the region and can range up to 23%. The percentage varies depending on total demand which generally runs between 10 and 13,000MW. It is important to note that none of the electricity produced at Indian Point is sold directly to industrial or residential consumers. It is sold to either Consolidated Edison or New York State Power Authority as part of the "basket" of electricity they use to meet the needs of customers in the region.

The region consists of Westchester and NYC, the metropolitan are. However, the entire region must be considered as a whole when generating capacity or percentages of use are considered. This is because power from many different sources is used to fill the "basket"of electricity which serves the region . You cannot divide the capacity of the generators at Indian Point by the amount of electricity used to get a percentage of use for either NYC or Westchester alone. The mix of purchased electricity is subject to market conditions and long term contracts, just like any other business arrangement on the free market. The market has worked as a credible mechanism for meeting changes in the supply side of the equation should Indian Point be removed from the mix. Certainly when either of the generators at Indian Point has been down for prolonged periods, the market has adjusted at little or no extra cost to the consumer.

The following figures which detail the distribution of power to the region are from 2003.

IP2

Indian Point 2 produced 1,000 MW and sold its power to Consolidated Edison. Con Ed, like NYPA, purchases electricity from different sources. Con Ed distributes approximately 10,000MW to 13,000MW daily throughout the region which covers both Westchester and NYC. This figure includes the amount provided NYPA and transmitted by Con Ed. Like NYPA, Con Edison purchases wholesale and is responsible for providing retail electricity to its own customers which are residential and non-government businesses in Westchester County and New York City. It does not sell outside of this region. Because the power it purchases comes from a variety of sources, it is not possible to arrive at the percentage of this figure contributed by Indian Point for use in part of the region such as NYC. All of the electricity purchased from different sources goes into the same "basket" for the region which includes NYC and Westchester.

The only accurate figure is one which includes the entire region, both NYC and Westchester. An example of this is 1,000MW, the production capacity of IP2, divided by 11,000MW which is the total amount of megawatts used by Con Ed in the chart below. In this case Indian Point contributed a maximum of 9% of the electricity sold to Con Ed for use in the region. Adding the percentage of use from NYPA and Con Ed does not produce an accurate figure of regional use because Con Ed buys and distributes so much more electricity. Total capacity divided by total purchases yields the accurate percentage of use and, of course varies, depending on the amount used.

Westchester County

345,000 customers 1,430MW
New York City
2.8 million Customers 9,570MW
Total: 11,000MW
Source: Con Ed

IP-3

Indian Point 3 produced 986MW which it sold to the New York Power Authority. In addition NYPA used an additional 5,500MW from its own plants for a total of 6,486MW. They purchased additional electricity from Canada and New England as needed. This means that no more than 15% of the total amount of power sold by NYPA to Westchester and NYC is generated at Indian Point 3 on any given day when NYPA purchases the entire capacity of the plant. (986MW divided by 6,486MW) The percentage can frequently be less if NYPA obtains cheaper electricity from other sources. In which case, Entergy can then sell additional electricity on the daily market at a premium. New York City and Westchester are part of the same NYPA region. All of the electricity purchased by NYPA for the region goes into the same "basket." It is not possible to break down this figure in order to arrive at a percentage used for part of the same region, that is, Westchester or NYC alone. Given the way the system works, they must be considered as a whole.

NYPA provided energy for the following customers:
Westchester County
Municipal customers 40MW
Government buildings customers 75MW
Westchester Airport 0.63MW

Total Westchester megawatts from NYPA : 115MW
Source: NYPA

New York City
Municipal Government 920MW
NYC Housing Authority 245MW
MTA (Trains) 615MW
Port Authority 35MW
State Buildings 60MW
Javits Convention Center15MW
Other 10MW
JFK Airport 0MW (self-generating)
La Guardia 15MW

Total New York City megawatts from NYPA: 1915MW
Source: NYPA

Of the 6,468MW purchased by NYPA from in-city and out-of-city generation a total of 1915MW was used in NYC. The rest were sold elsewhere. Please note, all of this electricity used by NYPA is NOT from Indian Point. Therefore, it is wrong to divide the amount of electricity used in NYC by the production capacity of Indian Point 3 in an attempt to derive the percentage of electricity produced by Indian Point used in NYC. (986MW/1915MW) An accurate calculation would be the total capacity of the plant divided by the total megawatts of electricity purchased by NYPA which is 6,486MW. (986MW/6,486MW) This means that the maximum amount of electricity produced by this plant for municipal and corporate clients can be up to 15%.

Independent System Operator Data

January 14, 2003

NYC total local generating capacity:	8,707 Megawatts
NY State total generating capacity:	36,000 Megawatts

August 9, 2001

NY state maximum ever peak:	30,983 Megawatts

When looking at the electricity market it is also necessary to consider generating capacity and who owns the transmission lines. According to the ISO on Jan. 14, 2003, the peak winter day that year, Con Edison transmitted 8,196MW to NYC and Westchester. This includes the amount supplied by both Con Ed and NYPA since only Con Ed transmits electricity. Indian Point could have contributed a maximum of 24% of this electricity if all of its power output were needed. But since the in-city generating capacity exceeded the demand, Entergy could have been released to sell significant amounts of its electric production on the spot market for that day. In terms of its impact on the state, Indian Point contributed a maximum of 5.5% of the state's generating capacity. (2,000MW/36,000MW = 5.5%)

July 3, 2002,

NYC peak use: 10,500 Megawatts
NYC import from PJM system: 1,000 Megawatts
NYC import from upstate: 4,000 Megawatts

According to the ISO, on July 3, 2002, Con Ed transmitted 12,086MW to NYC and Westchester. This total includes the amount supplied by both Con Ed and NYPA since only Con Ed transmits electricity. Indian Point at 2,000MW contributed up to 16% of this electricity as peak generating capacity was exceeded. It is not possible to tell the percentage of electricity from Indian Point that was used to meet the needs of either NYC or Westchester as the region must be considered as a whole.

To arrive at a figure for Indian Point's contribution to the electricity used in the region, it is necessary to divide the generating capacity of the plant by the entire amount of electricity both NYPA and Con Ed purchase. This will give you the "up to a certain amount" figure which was discussed earlier. Ambiguities in this figure include in house generating capacity and the purchase of cheaper electricity from other sources. As these figures make clear, the replacement for electricity from Indian Point is a relatively small percentage of total usage and nowhere near the figure of up to 40% which is frequently cited by Entergy in its commercials and presentations. Their figure is derived by using a day and time when there is a much lower usage. This is typically early in the morning on a spring or fall day before people get up to go to work and when heating of air conditioning is not necessary. It is not a realistic reflection of usage and has been used to mislead the public and elected officials about the importance of Indian Point to the power supply.

Replacement Options

Replacement options for the electricity produced at Indian Point are available and more can be planned for in an orderly manner without disruptions to the supply of electricity as the plants reach the expiration date of their original licenses. This has been well documented by both the Levitan Report and The National Academy of Science study, "Alternatives to the Indian Point Energy Center for Meeting New York Electric Power Needs." It is well within the purview of county and state governments to develop an

energy portfolio that will more than compensate for the base load electricity generated at the plant by this time and for the market to respond by providing additional generation. Replacing 2,000 MW of base load generation with an equal amount of base load electricity is unnecessary for the integrity of the system if demand side options, supply side options and transmission improvements are instituted as part of reasonable and efficient energy policy. The way electricity is priced by the Independent System Operators also needs to be looked at carefully to make the cost of individual means production more responsive to the market. As it stands now, variable local sources of electricity from other plants set the price for the hour. This price is frequently far above contracted costs for the electricity produced at Indian Point and disassociated from any costs of production.

Replacement options for the electricity produced at Indian Point are available, and more can be planned for in an orderly manner without disruptions to the supply of electricity as the plants reach the expiration date of their original licenses. This has been well documented by both the Levitan Report and The National Academy of Science study, "Alternatives to the Indian Point Energy Center for Meeting New York Electric Power Needs." It is well within the purview of county and state governments to develop an energy portfolio that will more than compensate for the base load electricity generated at the plant within this time frame and for the market to respond by providing additional generation.

Replacing 2,000 MW of base load generation with an equal amount of base load electricity is unnecessary for the integrity of the system if demand side options, supply side options and transmission improvements are instituted as part of reasonable and efficient energy policy. The way electricity is priced by the Independent System Operators also needs to be careful assessed. The cost of production of different means of generation is not always reflected in the hourly selling price of electricity. As it stands now, variable local sources of electricity from other plants set the price for the hour. This price is frequently far in excess of contracted costs for the electricity produced at Indian Point and is disassociated from costs of production. The current system is not an efficient or effective use of resources as it uses a base load plant to meet peak demands at a premium price.

Electricity not needed to meet contractual demands on a daily basis is made available to the Independent System Operators for dispatch elsewhere.

Bids are submitted by operators on a day- ahead basis based on variable operating costs like fuel, labor, taxes, and capitol recovery costs. While the NYISO dispatches the plant with the lowest bid first, it is the lowest bid that sets the market energy price for the hour. This same price is then paid to other generators for subsequent sales, no matter the cost of the electricity they have generated. Given this day- ahead, hourly- assigned cost method of pricing electricity, and the uniform cost of producing base load electricity, The National Academy of Science Report characterizes Indian Point is a "price taker, not a price setter. This means that the system frequently allows the electricity from Indian Point to be sold at a premium over and above the cost of production.

While this maximizes revenue for Entergy, it does nothing to encourage conservation or to lower the cost of electricity being sold to providers. A more efficient and practical approach to pricing electricity would be to tie selling costs to the generating costs for each method of production. This kind of reform is a state responsibility and Peter Grannis, head of the Department of Conservation, reported on November 29th at the Global Warming forum held in Cortlandt Manor that the Public Service Commission is investigating ways to "break the link between production and industry profits." Utilities make their money by pushing consumption not conservation and the PSC is now looking at alternative business models that would be more responsive to today's circumstances.

As the figures above make clear, the electricity produced at Indian Point is important to the reliability of the grid during peak summer usage periods, usually limited to the hottest days in August when air conditioners are operating at full force. There are other ways to compensate for this peak demand and provide for anticipated increased demand without the electricity from Indian Point as are outlined below.

In addition, policy makers and consumers in our region are increasingly aware of the greenhouse gases associated with the production of electricity. These gases are produced as part of the nuclear fuel cycle. Many studies indicate that nuclear energy produces approximately the same amount of green house gases as natural gas. This will come under increasing scrutiny in a carbon constrained world where alternative sources such as wind and solar have much smaller emissions when their fuel cycle is taken into consideration. It is to be noted that neither solar or wind energy produce highly toxic waste as a by product. Shipping and storage of high level radio

active waste is another cost factor frequently overlooked with nuclear energy. In short, Indian Point is an aging generating unit which provides up to 16% of the electricity used within the region. There are large unknown costs associated with the waste it produces and the longer it operates the more waste there will be to deal with. It is a prime terrorist target. The electricity can be replaced in many different ways which are detailed below without threatening the stability of the grid. The health and safety of the 21 million people in the metropolitan area requires that the operating license for these two nuclear reactors not be renewed.

Demand Side Options

Demand side options represent the cleanest and cheapest form of electricity replacement. Reducing peak loads is far more economical than the cost of installing additional capacity and is already being done across the country. A well thought out energy policy incorporates a portfolio of specific numbers of saved megawatts and lists how goals will be achieved.

In New York, NYSERDA has three programs already in effect:

*

The Peak Load Reduction Program which is expected to conserve 355 to 375 MW annually;

*

Enabling Technology for Price Sensitive Load Management which is expected to avoid the need for 308 MW

*

Keep Cool Program which anticipates a 38 to 45 MW savings;

These programs have saved approximately 700 mega watts and illustrate how demand side options can reduce peak demand. Reducing peak demand means that generating capacity and reserve margins can both be reduced. Thus, according to the National Academy of Science study, investments in reducing peak demand through energy efficiency measures can be valued at 118 percent of the actual reduction in megawatts because it avoids the

addition of new generating capacity with all its attendant costs. Consolidated Edison has established several demand management programs with the goal of reducing peak load growth by 535 MW; these programs use energy efficiency, smart equipment choices, load reductions programs and distributed generation. The New York Power Authority has committed $100 million a year for energy efficiency projects as detailed in the Contentions below which were submitted by the New York Attorney Generals Office to the Nuclear Regulatory Commission.

Another way to measure the electricity saved is in negawatts. Negawatt power is a way of supplying additional electrical energy to consumers without increased generation capacity. The creation of markets for the trading of negawatts leads to increased efficiency. The concept was introduced by energy expert Amory Lovins, Director of the Rocky Mountain Institute. He first used the term in a 1989 and it has proven to be an efficient measure of saved electricity. The concept works by utilizing consumption efficiency to increase available market supply rather than by increasing plant generation capacity. For example an industrial consumer can advertise for bids for 100 MW hours. A supplier may find energy efficiencies within an unrelated business and contract to improve their heating or lighting for instance. The savings, or negawatts, can then be sold through the utility to the industrial consumer. This becomes an arbitrage transaction rather than an in house process and does not require increased generating capacity from the electric power utility. Entrepreneurial forces are focused on making money by selling negawatts, or saved units of electricity, and the entire system benefits.

Energy consumers may also reduce energy consumption for a few hours to "generate" negawatts. For example, by shutting off air conditioners for a few minutes on the hour, a lot of energy can be saved over a short period of time. Con Ed has already initiated a program for customers in Westchester which provides a programmable thermostat for air conditioners. The installation is free and the customer receives a stipend. In return they allow Con Ed to turn off their air conditioner for five minutes on the hour a limited number of times daily should electricity supplies run low during peak demand times. In this case the utility is producing and transferring the negawatts. In an expanded market many other vendors could do the same thing and the basic infrastructure remains unchanged. This is a practical and efficient way to get more work done with less electricity without building additional base load generating capacity to replace Indian Point.

Better price signals to the consumer, such as off peak discounts for electricity usage, could change the load profile and allow a better pairing of demand to capacity. One example of this is using discounted off peak pricing to encourage people to shift the time for energy intensive household chores such as washing and drying laundry. On a system-wide basis the shift could be significant. It would also reduce the overall cost of electricity because peak power is more expensive than average costs. While this would not reduce use, a more vigorous educational campaign along with a wider out reach for promotion of tax credits for the installation for energy efficient measures – such as windows and appliances – would do so.

Experiments have been done with meters inside the home which measure the amount of electricity used by household appliances as they are running. The results clearly indicated that when consumers become more aware of how much electricity is being used and where it is being used, they took steps to reduce usage. Electricity is invisible to most consumers. Making it more visible, that is, giving people information about how to save electricity and making it worth their while to do, can so can result in significant savings. A bill currently pending in the New York State Legislature, (Number A8739) would amend the public service law, in relation to providing real time smart metering technology to residential electricity customers. The purpose of the bill is to facilitate the use of smart metering so that households can reduce the cost of electrical services. It would help consumers reduce the peak demand for electricity.

The experience in California validates this point and illustrates that a 15% reduction in electricity usage can be achieved. The fact that a state on the east coast, Vermont, has held their energy use constant while expanding their economy is proof that this can be done in our region. In many ways it is a community mind set that establishes the parameters of what is possible. In Burlington even hotel guests are expected to recycle. They are also given the option of not having their sheets changed every day in order to save the electricity used in washing and drying them. We have a lot of educating to do in New York to reach this mind set, so the potential savings are huge. Conservation as practical alternative to the electricity has been thoroughly analyzed in the report prepared by the Attorney General and the Department of Environmental Conservation for the State of New York and submitted to the Nuclear Regulatory Commission.. We reference their work below and agree with their conclusions.

EXHIBIT JJJ

EXHIBIT JJJ

EXHIBIT JJJ

January 7, 2007

Ms. Lisa Rainwater
Riverkeeper, Inc.
828 South Broadway
Tarrytown, NY 10591

Dear Ms. Rainwater:

As a person who appears to embrace the need of truly independent oversight of the Indian Point Energy Center, I thought the enclosed information would be of great interest to you. I have enclosed several documents that I believe you will find at first glance unbelievable; and then when the potential consequences sink in, I hope you find them even more disturbing than a few malfunctioning sirens or underground radioactive water, that has not flowed beyond the plant boundaries.

The documents outline a plan that Entergy Nuclear Northeast has implemented at their Northeast plants that TOTALLY ELIMINATES the quality control departments (day to day oversight), and severely cut the staffing of their quality assurance departments (general oversight). You are probably asking, "How can they do that". We have asked the same question, as "independent inspections" are codified in 10CFR50 Appendix B. We have been told that 10CFR50 does not mandate a QC department; it mandates "independent inspections". What Entergy has done over the past several years is write QC out of their Quality Assurance Program Document, and put in general phrases about "independent inspections". They have included a short phrase stating that personnel performing inspections work for the QA Manager, while they are performing inspections. That would hilarious, except for the fact that many of those craftsmen wouldn't even know the QA Manager if they were on the elevator with him.

So what exactly have they done? Entergy Nuclear Northeast's upper management has dissolved the QC Departments at each of their plants, and is now having each department perform their own inspections!!!!! For example, Bill, Joe and Sam are maintenance mechanics. On one job Bill and Joe perform the work, while Sam inspects the work. On the next job, Bill and Sam do the job, while Joe performs the inspections. Entergy has stated time and time again they are not violating any requirement, as someone other than those doing the work is performing each inspection.

I am writing to you as a former member of the QC Department. I am not writing due to "sour grapes", as each of the former QC Department staff members still has a job at IPEC, and none of us have received a pay cut. I am writing to you because we (former QC staff) truly believe the dismantling of the QC Department has very serious safety implications at IPEC. When this plan was first announce several years ago by the Northeast Director of Corporate Oversight, Mike Columb, "we" expressed our serious reservations to the plan. With more than 25 years of quality control experience each, we had many examples from nuclear plants around the world that this was a poor idea. Of

the many stories we shared with Mr. Columb, the recurring one was mechanics arguing that an unacceptable condition was "close enough"; that by spending the TIME to rework the part won't make it that much better. Now that the mechanics inspect the work of their peers, we now say amongst ourselves that "close enough", has now become "good enough".

Another reason given for implementing this plan was to make the workers accountable for their own work. Let me put that argument into perspective. Such logic would be like the State saying that since NYS citizens are inherently honest, and to save a substantial amount of money on police patrols, the State was going to make drivers and passengers accountable for the driver's driving. When a passenger identified a driver violating a traffic law, they would report the violation. That logic would be simply laughable, except that is what Entergy Nuclear Northeast has done to quality oversight at its Northeast Plants.

Please review the enclosed documents, and I trust that you too will agree that the immediate risk of not having quality control oversight has far greater immediate and long term consequences than the current discussions of sirens, evacuation plans and ground water contamination.

Since the NRC is fully aware of this policy and has not taken any action, we are taking the time to write our Senators, Congressmen, and local government officials, hoping that your collective resources can make a change to a potentially disastrous policy.

Signed: A sincerely concerned Entergy Nuclear Northeast employee, and the former QC Staff.

June 3, 2005
IP-QAS-05-007

MESSAGE FROM JOE PERROTTA, QA MANAGER

As part of a fleet alignment initiative, as of June 5, 2005, the Quality Assurance Department Quality Services/Inspection function will complete its transition to Maintenance and Programs &Components Engineering (P&CE) Departments.

Maintenance inspection (ANSI type verifications) will be performed within the Maintenance Department and all Nondestructive Examinations (UT, RT, PT, MT, VT) will now be performed by P&CE. Previously only NDE UT and RT were performed by P&CE. In addition, the responsibility for Civil and Coatings Inspections will be transferred to Design Engineering.

QA personnel are being transferred to the respective organizations to support this initiative.

Implementing procedures have been revised to reflect this change. As with any new process there will be a period of adjustment.

ENN-MA-102, "Maintenance Inspection", has been generated and issued for the inspection process, clearly defining roles and responsibilities to ensure compliance when implementing the program within Maintenance.

ENN-MA-102 identifies a Maintenance Inspection Coordinator (MIC). For IPEC our designated MIC is Mark Gettleman. Mark's primary responsibility will be the designation of required inspection points, within Maintenance activities in accordance with ENN-MA-102, adding and deleting inspection points as applicable.

See the attached memo for details of the transitions.

If you have questions, contact Mark Gettleman X8523 (Maintenance Inspection Coordinator), Norm Nilsen X8686 (Maintenance), or Nelson Azevado X6048 (P&CE).

Attachments: Chris Schwarz, VP Operations, Transition of QC Inspection to Maintenance and Engineering

Entergy

Date: June 3, 2005

To: IPEC Personnel

From: Mike Colomb, Acting VP Operations

Subject: Transition of ANSI Inspections to Maintenance, All NDE Examinations to Site Engineering and the Use and Understanding of Maintenance and Other Site Documentation

As the Quality Assurance Department will no longer have a Quality Control Section within the department, all ANSI mechanical, electrical and instrument & control inspections will be the responsibility of individuals qualified and certified to ANSI N45.2.6 within the Maintenance Department. All nondestructive examinations (NDE), which includes volumetric, surface, visual, welding and ANSI inspections for civil and concrete activities, will be conducted by site Engineering. At this point in time not all of the Maintenance Procedures, Technical Mechanical Specifications and other site documents have been revised to reflect this change in line ownership of the inspection and examination process reflected in station procedures.

Based on this transition, the following guidelines have been assembled to assist station personnel in understanding the organization that should be contacted or reflected in work instructions such as work orders, modifications and procedures.

1) If the term "Notify Quality Assurance or Quality Control for a Start of Work" appears in a Maintenance Procedure, sign, initial and date the step as recognition that a QC organization no longer exits at IPEC. This step was used as notification to QC as a possible activity for process monitoring. The Quality Assurance Department will no longer have a Quality Control organization within the department to respond to the notification.

2) All pre-existing "Quality Control Inspection Hold Points", except for code required and non-routine inspections, as defined in ENN-MA-102, are no longer valid or in effect. All inspections will be selected and indicated in appropriate work documents in accordance with ENN-MA-102. Such documents will be identified as requiring inspection points by a qualified inspector. Any specific hold points in work documents will be individually stamped as a qualified inspection point.

3) If a Maintenance Procedure, Technical Mechanical Specification or other site document has a step or references one of the following examinations such as, radiography (RT), ultrasonic examination (UT), magnetic particle (MT), liquid penetrant (PT), visual examination (VT-1, VT-2, & VT-3), weld examination, coatings, and civil inspections contact Programs, Component & Engineering (PC&E) for the required support.

4) If a modification is being developed and nondestructive examinations as well as civil or coating examinations/inspections are required, Engineering will be responsible for providing the required support.

5) If a modification is being developed the original construction criteria shall apply requiring the applicable "Inspection" for the ANSI activities involving "Mechanical, Electrical, and Instrument & Control" tasks. The required support shall be provided by the Maintenance Department.

6) The Maintenance Department will have a Maintenance Inspection Coordinator (MIC), who will be responsible for reviewing the 12-week schedule and selecting safety related activities whether routine or non-routine maintenance for ANSI inspections. The MIC shall be ANSI N45.2.6 qualified and certified.

7) Planners shall be required to reference this memorandum when planning work orders involving Maintenance Procedures, Technical Mechanical Specifications and other site documents to determine which organization should be contacted when inspections or examinations are required. The ENN-WM-105 procedure, entitled, "Planning", states in Section 4.0, "Responsibilities", specifically 4.2.6, "That the Planner is responsible for specifying Hold Points, Verifications, and Witness Points per site requirements." Based on this statement, the Planner will rely on the MIC to determine the ANSI inspections for routine and non-routine maintenance by T-8. (As required in EN-MA-102.). The planner will use site documentation such as, specifications, drawings and procedures to determine when NDE examinations are required or request assistance from Engineering

A new Maintenance procedure, EN-MA-102, entitled, "Inspection Program", has been issued to cover how ANSI required inspections would be selected and conducted. The required NDE examinations are covered in the Nondestructive Examination Procedures. These procedures can be found in the Nuclear Management Manual.

These instructions are to be followed until the site-specific procedures are revised to reflect the line ownership of inspections and examinations.

RP/RMP

cc: Michael Colomb
Richard Patch
Richard Petrone
Mel Garofalo
Joe Perrotta

Entergy

Interoffice
Correspondence

April 17, 2006
IP-QAS-06-003MC

TO: IPEC Personnel

FROM: J. Perrotta, QA Manager
T. Carson, Maintenance Manager

Subject: TRANSITION OF ANSI INSPECTIONS TO MAINTENANCE, ALL NDE EXAMINATIONS TO SITE ENGINEERING, AND THE USE AND UNDERSTANDING OF MAINTENANCE AND OTHER SITE DOCUMENTATION

As the Quality Assurance Department no longer has a Quality Control section within the department, all ANSI Mechanical, Electrical, and Instrumentation & Control inspections are now the responsibility of individuals qualified and certified to ANSI N45.2.6 within the Maintenance Department, in accordance with EN-MA-102 Inspection Program.

Based on this transition, not all of the Maintenance procedures, technical maintenance specifications, and other site documents have currently been revised to reflect this change. The following guidance, as originally identified by memorandum issued on June 3, 2005 by Mr. Michael Colomb, Acting VP Operations, is being reissued. Additional guidance is being added for clarification.

1.) All pre-existing "Quality Control Inspection Hold Points", except for code required and non-routine inspections, as defined in EN-MA-102, are no longer valid or in effect. All inspections will be and are selected and indicated in appropriate work documents in accordance with EN-MA-102. Such documents will be identified as "Requiring Inspection Points by a Qualified Inspector". Any specific hold points in work documents will be electronically entered, or hold points individually stamped as a qualified inspection point.

2.) For further clarification and in accordance with EN and site procedures, all "Pre-existing Quality Control Inspection Hold Points", except for code required and for non-routine inspections as identified in EN-MA-102, shall be:

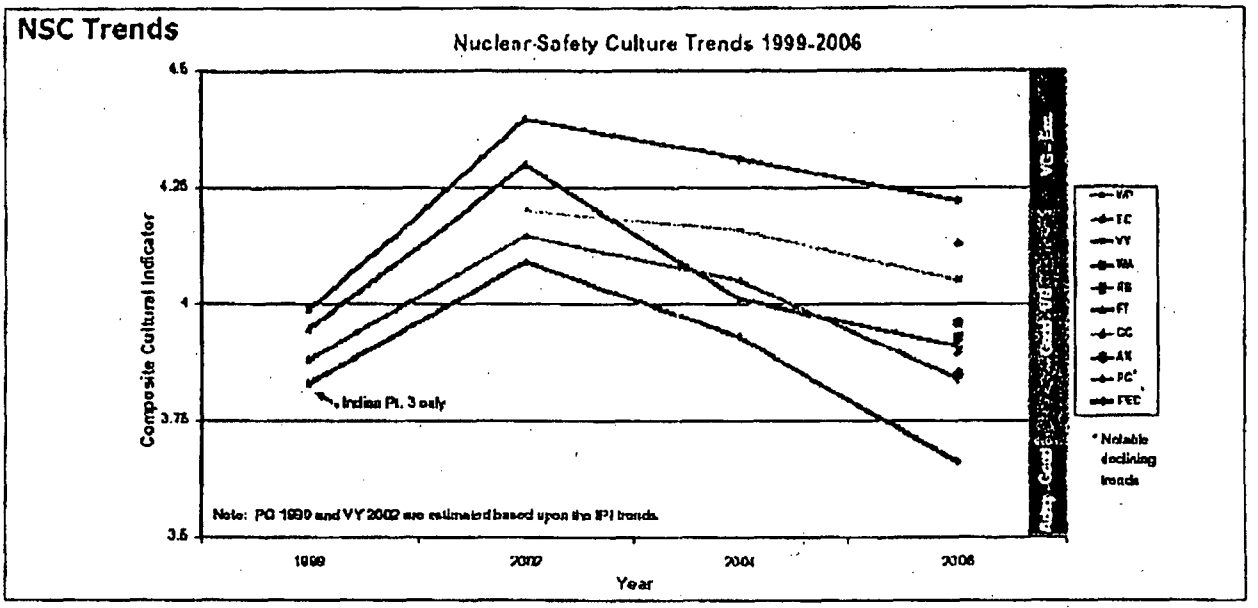
- N/A'd as Not Applicable
- Initialed and dated (preferably by a Supervisor) or Designee
- Clarification with an explanation stating that "QC No Longer Valid or In Effect"

These instructions are to be followed until the site-specific procedures are revised to reflect the line ownership of inspections and examinations, and the hold points are formerly deleted.

MG/cc

Cc: T. Carson
M. Colomb
M. Gettleman
P. Morris
R. Patch
J. Perrotta
File 2.2
Records

Overall Nuclear Safety Culture Trends



The overall trend in Nuclear Safety Culture has been declining since the 2002 survey. Indian Point has shown a sharper decline than other Entergy fleet plants

Cultural Dimension Details

Cultural Model / Major Functional Orgs.	IPEC	OP	MT	EN	NA	SS
NUCLEAR SAFETY CULTURE	3.66 ↓◆◆	3.43 ↓◆◆◆	3.26 ↓↓◆◆◆	[illegible]	[illegible]	[illegible]
NS VALUES, BEHAVIORS & PRACTICES	3.49 ↓◆◆	3.23 ↓↓◆◆◆	3.11 ↓↓◆◆◆	[illegible]	3.70 ◆	[illegible]
SAFETY CONSCIOUS WORK ENVIRONMENT	4.22	[illegible]	[illegible]	4.55	4.43	4.39
EMPLOYEE CONCERNS PROGRAM EFFECTIVENESS	3.22 ↓◆◆◆	2.89 ↓↓◆◆◆	2.89 ↓↓◆◆◆	3.50 ◆	3.50 ◆◆	3.50 ◆◆
GENERAL CULTURE & WORK ENVIRONMENT	3.30 ◆◆◆	3.08 ◆◆◆	2.87 ◆◆◆	3.62 ◆	3.54 ◆◆	3.54 ◆◆

◆ > 10% neg. response; ◆◆ > 15% neg. response; ◆◆◆ > 20% neg. response
↑ or ↓ Notable Positive / Negative Trend (Mean 5-10% higher / lower)
↑↑ or ↓↓ Significant Positive / Negative Trend (Mean >10% higher / lower)

Indian Point has maintained a very good to excellent (blue boxes) Safety Conscious Work Environment but shows notable declines among some worker groups in area such as Employee Concerns Program and general work culture (morale issues). Note: green= good, yellow= nominally adequate

Exhibit FP No. 1

The Associated Press

March 3, 1993, Wednesday, AM cycle

Problems With Fire-Retarding Material Went Uncorrected, Panel Told

BYLINE: By H. JOSEF HEBERT, Associated Press Writer

SECTION: Washington Dateline

LENGTH: 511 words

DATELINE: WASHINGTON

Federal regulators for years did nothing to correct problems with a fire-retarding material at nuclear power plants because they relied on industry assurances, a congressional panel was told Wednesday.

A report by the **Nuclear Regulatory Commission's** inspector general said **NRC** staff members who approved the fire-protective material "operated under the premise that the information was accurate because it was submitted under oath."

The Justice Department has begun a criminal investigation into whether the **NRC** and utilities were misled about the fire-retarding capabilities of Thermo-Lag, a gypsum-like material used to protect critical electrical wires at nuclear power plants in case of fire.

The material is used in 79 nuclear power plants nationwide. The **NRC** last year directed that operators of the plants step up physical monitoring of the plants to detect problems early until a decision is made what to do with the material.

The NRC last summer acknowledged there were problems with the material, manufactured by Thermal Science Inc. of St. Louis, and that the agency had largely ignored concerns raised by utilities and others about the material.

In a follow-up report submitted Wednesday to the House Energy and Commerce investigations subcommittee, the NRC said agency staff members over more than a decade made no effort to independently review test results and findings submitted by the manufacturer of Thermo-Lag and claims that the material met NRC requirements.

"The management philosophy was described by one staff member as 'You have to trust somebody sometime,'" said the inspector general's report. It said there also was pressure to approve the material and "not delay (nuclear plant) operation."

NRC Chairman Ivan Selin told the subcommittee that the internal investigation uncovered "numerous missed opportunities" to identify and correct the problems with the material.

"There were serious deficiencies on the NRC's part, as well as on the part of the utilities involved," Selin said. He said the NRC would determine after it completed its investigation whether to take disciplinary action against any of the agency officials involved.

The NRC required fire-protective materials around electrical cables at nuclear plants after a 1975 fire at the Browns Ferry reactor in Alabama damaged more than 1,600 electrical cables.

Thermo-Lag was approved by as a protective barrier in the early 1980s. The NRC, however, never conducted independent tests to determine if the material met federal standards, relying instead on reports submitted by the industry.

Over 10 years there also were a number of reports - some from utilities - indicating that the material failed to meet NRC requirements, including one that it produced toxic gases when burned. But each time, the NRC failed to pursue them, agency investigators said.

"The NRC blindly accepted the utilities' assurances," said Rep. John Dingell, D-Mich., chairman of the subcommittee and of the full Energy and Commerce Committee. "This is hardly a regulatory success."

LANGUAGE: ENGLISH

States News Service

March 3, 1993, Wednesday

CONGRESSIONAL PANEL SAYS AREA NUCLEAR POWER PLANTS MAY EMPLOY DEFECTIVE FIRE RETARDANTS: Protectant Supposed To Aid In Emergency Shutdowns

BYLINE: By Jennifer Babson, States News Service

LENGTH: 713 words

DATELINE: WASHINGTON

A fire retardant used at Limerick and the Peach Bottom atomic power station to protect electrical cables needed to shut down these facilities during emergencies, may be faulty, a U.S. House panel heard Wednesday.

Witnesses appearing before a House Energy and Commerce subcommittee, said the **Nuclear Regulatory Commission (NRC)** turned a blind eye to contradictory and sometimes sketchy test results conducted on THERMO-LAG, a fire retardant manufactured by Thermal Science Inc. (TSI), of St. Louis.

Under **NRC** regulations, the retardant material must be able to withstand very high fire temperatures -- for one hour if the plant has a sprinkler system, three hours if it doesn't.

But according to Leo Norton, the **NRC's** Assistant Inspector General of Investigations, in one test, THERMO-LAG collapsed within 22 minutes. He also said the **NRC** never bothered to personally test the product, preferring to take the word of vendors and utility company officials who swore under oath test results showed the product worked.

"The **NRC**, to a considerable extent, relied on people swearing to particular information," Norton said. "If information was submitted under oath, they would accept it, whether it was the vendor or the licensee."

At Wednesday's hearing, Energy and Commerce Committee Chairman John Dingell, D-Michigan, charged that THERMO-LAG has resulted in "substandard fire protection" for nuclear plants that employ the material.

In response to these allegations, nuclear power plant officials said they're taking added safety precautions, some of which have been ordered recently by the **NRC.**

Bill Jones, a spokesman for the Philadelphia Electric Company, which operates both the Limerick and Peach Bottom plants, said the company has implemented additional fire safety precautions, while it waits for the agency to take further action.

"Whatever needs to be done, we'll do it, in the meantime, I really don't think the public needs to be concerned," Jones said.

"Our concern is to prevent a fire from happening in the first place," he added. "We feel as long as we can safely prevent fires, you won't need fire protection barriers to protect you."

David Williams, Inspector General for the U.S. **Nuclear Regulatory Commission,** also told lawmakers the **NRC** "did not conduct an adequate review" of the so-called 'tests' that many utility companies cited when they requested **NRC** permission to use THERMO-LAG.

A report Williams released in August of last year found that, "Between 1981 and 1991, the **NRC** staff did not observe any tests of THERMO-LAG. Further, the **NRC** staff did not investigate the qualifications of or visit the laboratory which purportedly supervised most of the THERMO-LAG tests." The **NRC** also didn't conduct any inspections of TSI.

And although **NRC** regulations stipulated that fire retardant performance tests be conducted by a 'nationally recognized fire testing laboratory,' the commission accepted the results of tests conducted by some companies that didn't fall into that category, and others with "no fire testing expertise."

Some tests also weren't conducted in accordance with **NRC** fire testing standards, and others were conducted by TSI, which had a financial stake in their outcome.

The **NRC** is currently investigating the effectiveness of THERMO-LAG. Shortly before Williams released his report in August of last year, the commission surveyed the nation's nuclear utilities to find out how many used THERMO-LAG. They also ordered plants to implement a series of additional fire safety precautions until the matter is resolved.

In a prepared statement, Ivan Selin, Chairman of the U.S. **Nuclear Regulatory Commission,** conceded the agency's lack of regulatory oversight may have contributed to a "questionable acceptance of the THERMO-LAG material in the first place."

But Selin placed the blame equally on the shoulders of utilities that chose to use the product. "There were serious deficiencies on the **NRC's** part, as well as on the part of the utilities involved," he said.

Although **NRC** "inquiries to date indicate that repairs of upgrading may be needed," Selin said the agency is holding off on further action until it has "adequately identified what criteria are appropriate to decide what standards have been met."

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Exhibit FP No. 2

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Office of The Inspector General

U.S. NUCLEAR REGULATORY COMMISSION

UNITED STATES NUCLEAR REGULATORY COMMISSION

INSPECTION REPORT

511

OFFICE OF THE INSPECTOR GENERAL
INSPECTION REPORT

ADEQUACY OF NRC STAFF'S ACCEPTANCE AND REVIEW OF THERMO-LAG 330-1 FIRE BARRIER MATERIAL

CASE NO. 91-04N

Harold L. Lessel 8/12/92
INSPECTOR DATE

George A. Mulley Jr. 8/12/92
INSPECTOR DATE

Leif J. Norton 8/12/92
ASSISTANT INSPECTOR GENERAL FOR INVESTIGATIONS DATE

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

August 12, 1992

OFFICE OF THE
INSPECTOR GENERAL

MEMORANDUM FOR: Chairman Selin
Commissioner Rogers
Commissioner Curtiss
Commissioner Remick
Commissioner de Planque

FROM: David C. Williams
David C. Williams
Inspector General

SUBJECT: INSPECTION OF THE NRC STAFF'S ACCEPTANCE AND REVIEW OF THERMO-LAG 330-1 FIRE BARRIER MATERIAL

The attached Office of the Inspector General (OIG) Report of Inspection addressed the adequacy of the staff's performance related to the acceptance and review of Thermo-Lag fire barrier material by the NRC. This inspection was initiated as a result of allegations received in early 1991 that questioned the adequacy of Thermo-Lag to provide the level of fire protection required by the NRC.

In addition to this inspection, OIG is conducting an investigation, in conjunction with the Office of Investigations, of Thermal Science Inc., the manufacturer of Thermo-Lag. Also, OIG is examining several allegations of NRC employee misconduct.

As always the OIG experienced full cooperation on the part of the staff. This body of work presented unusual complexities in coordination and cooperation between the staff and my office. Your role in the development of the ongoing OI/OIG Task Force was greatly appreciated. Because of health and safety considerations, the staff also set up a Special Review Team. The EDO and Senior NRR officials were instrumental in assuring that the Investigative Task Force and the Special Review Team worked effectively together. I am appreciative of their efforts as well.

If you have any questions regarding the OIG's report, I will be happy to meet with you at your convenience.

Attachment:
Report of Inspection

cc: J. Taylor

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This Office of the Inspector General (OIG) inspection was initiated in the spring of 1991, based on receipt of allegations that questioned the adequacy of Thermo-Lag 330-1. Thermo-Lag 330-1 is a fire barrier material manufactured by Thermal Science, Inc. (TSI), St. Louis, Missouri. The Nuclear Regulatory Commission (NRC) staff estimates that Thermo-Lag 330-1 is utilized in approximately 80-100 nuclear power plants to protect redundant safe shutdown electrical circuits from fire as required by NRC regulations. It has been alleged however, that the material does not provide the required level of fire protection and also, that the ampacity derating figures for Thermo-Lag 330-1 are actually much higher than the figures reported by TSI. Our inspection addressed the adequacy of the NRC staff's acceptance and review of Thermo-Lag 330-1, and the staff's response to reports of problems with Thermo-Lag 330-1 that were reported over a period of about 10 years.

On March 22, 1975, a fire occurred at the Browns Ferry nuclear power plant in Alabama. A Special Review Group (SRG) was established by the NRC shortly after the Browns Ferry fire to identify lessons learned and to make recommendations. The SRG concluded that improvements, in fire prevention and fire control were needed and proposed a number of recommendations. One recommendation involved the need to protect redundant electrical systems required to achieve and maintain safe shutdown in the event of a fire. The NRC provided immediate guidance on this issue to the nuclear power industry. In 1981, Appendix R was issued and Section III.G. specifically addressed the requirements involving the protection of safe shutdown systems. These requirements have been made applicable to all nuclear power plants.

One method of satisfying this safe shutdown requirement is to enclose the redundant electrical circuits with fire-rated barriers. Before licensees could use a fire barrier material to satisfy the requirements of Appendix R, the NRC required that the products have a fire resistance rating of either one or three hours. If a one hour barrier was chosen, an automatic sprinkler system was required. The NRC and industry required that this rating be achieved by having a nationally recognized, fire testing laboratory subject the fire barrier material to a standard fire exposure test.

In 1981, the NRC began receiving requests from licensees for acceptance of Thermo-Lag 330-1 to satisfy the safe shutdown requirements in Appendix R. Since its initial acceptance in 1981, Thermo-Lag 330-1 has been the fire barrier material most extensively accepted by the NRC and installed by licensees.

When electric cables are placed in trays and conduits and enclosed by fire barrier material, the temperature of the cable insulation increases because the heat generated by electricity passing through the cables is retained within the barrier. Since electrical cable insulation is vulnerable to premature degradation when operating at higher than

normal temperatures, the ampacity of the enclosed cables must be derated (lowered) to adjust for the insulating effect of the fire barrier material. Therefore, a low ampacity derating requirement would be an important consideration relative to the fire barrier material selected for installation in nuclear power plants.

The NRC requires that cable derating due to the use of fire retardant coatings be considered by utilities during plant design or when design changes are made to existing electrical system configurations. The NRC electrical staff is responsible for reviewing cable derating to ensure compliance with accepted industry practice.

Beginning in 1981, the NRC received reports documenting fire tests of Thermo-Lag 330-1 that were conducted by TSI. Fire tests conducted by TSI were witnessed by Industrial Testing Laboratories, Inc. (ITL), St. Louis, Missouri. A review of a number of ITL reports of fire tests conducted by TSI and witnessed by ITL disclosed that the TSI tests had not been performed in accordance with the required standards. For example, the test furnace and temperature measuring devices used by TSI during the tests did not meet the standards. Although the NRC requires a full scale fire endurance test, the tests conducted at TSI were "small scale" tests. NRC requirements state that a fire endurance test on barrier materials must be conducted by a nationally recognized, fire testing laboratory. The NRC staff accepted ITL test reports, and ITL test reports were used throughout the industry to qualify Thermo-Lag 330-1 for use in power plants. It has been recently determined that ITL had no fire testing expertise.

TSI fire endurance tests were reportedly validated by the presence of a representative from ITL, utility officials, and inspectors from the American Nuclear Insurers (ANI). OIG found that utility officials and ANI inspectors merely witnessed the conduct of fire tests. They did not inspect the test articles as they were being constructed by TSI employees, and they were often absent during significant portions of the fire tests.

Although the ITL test reports state the fire tests were supervised and controlled entirely by ITL, the ITL representative was present only as a witness to verify that a test was conducted. The test reports were actually written by TSI and then signed by the President of ITL with no substantive verification that the data in the reports reflected the actual tests. In some instances, the ITL President simply signed test report cover sheets for TSI without seeing the test report.

The NRC managers of the fire protection staff advised OIG that the NRC conducted reviews by auditing paperwork. The NRC staff considered it the responsibility of the utilities to provide accurate information concerning the conduct of the qualification tests. Consequently, the NRC did not find it necessary to observe qualification tests of Thermo-Lag 330-1.

In 1982, the NRC received from Susquehanna nuclear power plant two reports of TSI tests of one hour Thermo-Lag 330-1. In June 1982, the NRC fire protection staff

rejected both TSI reports because the tests were simulated and differed from the required fire testing standards. The NRC recommended that Susquehanna have a test conducted at an approved laboratory. The OIG inspection found that within months of rejecting the TSI tests submitted by Susquehanna, the NRC staff accepted a fire test from Washington Nuclear Project-2 (WNP-2) which was conducted using the same substandard procedures.

During the fall of 1982, TSI conducted two additional tests of Thermo-Lag 330-1 that passed and that had applicability to many power plants. These test reports were used throughout the nuclear power industry to qualify Thermo-Lag 330-1 with the NRC. Specific power plants that used these generic tests included Comanche Peak, Palo Verde, River Bend, Prairie Island, Callaway, and Susquehanna. ITL was witness to these tests which were conducted under the same inadequate conditions as previous TSI tests.

Ampacity derating

Originally, TSI reported to Comanche Peak that Thermo-Lag 330-1 would require a 10 percent ampacity derating. In 1982, TSI conducted an ampacity derating test with ITL as the witness and produced a derating figure of about 17 percent. During this same time period, manufacturers of other fire barrier materials conducted ampacity derating tests and reported ampacity derating figures far higher than those reported by TSI, some as high as 40 percent.

In 1986, an ampacity derating test on Thermo-Lag 330-1 was conducted at a nationally recognized laboratory-Underwriters Laboratories (UL). The UL test produced ampacity derating figures of about 31 percent for the three hour and about 28 percent for the one hour Thermo-Lag 330-1. These figures were significantly higher than those previously reported by TSI.

In the above test, UL officials told OIG that TSI refused to follow the UL ampacity derating testing procedure. After the TSI representatives left the UL facility, an additional ampacity derating test on Thermo-Lag 330-1 was conducted by UL which followed the UL ampacity derating test procedure. The second UL test produced ampacity derating figures for Thermo-Lag 330-1 of nearly 40 percent for the three hour barrier and 36 percent for the one hour barrier. These figures were not reported to the NRC.

Indications of inadequate performance of Thermo-Lag 330-1 not addressed by the NRC

During its inquiry, OIG learned of instances over the past ten years which were reported to the NRC and which questioned the ability of Thermo-Lag 330-1 to perform as claimed by the manufacturer. However, our review of much of this information disclosed that the NRC staff did not effectively respond to these indicators. Several of these instances are discussed below:

Inadequate TSI test reports submitted by Susquehanna

In June 1982, the NRC fire protection staff rejected two TSI test reports submitted by Susquehanna and recommended that a test be conducted at an approved testing laboratory. One reason for rejecting the tests was because the tests were not performed in accordance with adequate quality assurance procedures. In October 1982, however, the NRC staff accepted a test report from WNP-2 that was conducted at TSI in the same manner. The nuclear industry continued to use TSI tests that were documented in ITL test reports to qualify the installation of Thermo-Lag 330-1. OIG found no action by the NRC staff to address the fact that utilities were using TSI tests that were documented in ITL test reports to qualify their installation of Thermo-Lag 330-1. Nor was any effort made to resolve the fact that tests using the same TSI procedures were rejected and then accepted by the NRC.

10 CFR Part 21 Report on ampacity derating

On October 2, 1986, TSI notified the NRC by mailgram of ampacity derating figures that were significantly higher than those reported earlier by TSI. The earlier TSI figures were used by utilities to design electric power systems utilizing Thermo-Lag 330-1. The TSI mailgram was administratively recorded as a Part 21 Report by the NRC. In December 1990, the Part 21 Report was closed by the NRC without taking any action.

Comanche Peak report on new ampacity derating figures

In 1987, Comanche Peak provided a written report to the NRC detailing new ampacity derating figures provided by TSI. The new figures were 31 percent and 20 percent, substantially higher than the 10 percent originally reported by TSI and used in the initial cable sizing calculations at Comanche Peak. In its report to the NRC, Comanche Peak stated that failure to consider the additional derating of power cables due to Thermo-Lag 330-1 installation could cause the power cables to exceed the design temperature rating of the cables. OIG found no NRC follow-up with TSI in order to obtain an explanation for the significant increase over the ampacity derating figures initially provided by TSI to Comanche Peak.

Allegations regarding the performance of Thermo-Lag 330-1

In March 1989, the NRC received an allegation that, when burned, Thermo-Lag 330-1 gave off lethal gases. In support of this concern, the alleger provided the staff with information from a test of Thermo-Lag 330-1 documented in a May 1986 SwRI report. During an Allegation Review Board meeting it was decided to close the allegation without further action.

The alleger also informed the NRC about a fire endurance test that involved Thermo-Lag 330-1 as a fire barrier used in conjunction with a fire penetration seal. The alleger

pointed out that the Thermo-Lag 330-1 had disintegrated during the test. OIG did not find any indication that the NRC staff conducted an inquiry into the information that Thermo-Lag 330-1 had been consumed in a fire test.

Problems with Thermo-Lag 330-1 at Comanche Peak

In 1989, NRC Region IV was informed that panels of one hour Thermo-Lag 330-1 were arriving at Comanche Peak from TSI, that measured less than the required thickness. Subsequently, Comanche Peak management discussed the situation with TSI. In a July 13, 1990, letter to the NRC, Comanche Peak explained that the behavior of Thermo-Lag 330-1 under fire conditions is dependent on the density of the product and not on the thickness. After reviewing the Comanche Peak July 13, 1990, letter and without further inquiry of TSI or Comanche Peak, Region IV accepted the resolution of the matter and closed this issue.

OIG learned from the NRC and National Institute of Standards and Technology staff that the Comanche Peak quality control practice of checking weights was not an accurate indication of the performance of Thermo-Lag 330-1 panels. The identification of this problem provided another opportunity for the NRC to inquire into the performance of TSI and Thermo-Lag 330-1 that was not pursued.

Concerns about the performance of Thermo-Lag 330-1 at River Bend

In December 1989, the River Bend nuclear power plant submitted an Informational Report to the NRC regarding an October 1989 test of Thermo-Lag 330-1 that failed. As a result, River Bend conducted an investigation and identified several generic issues with Thermo-Lag 330-1 that were outlined in the Informational Report. The OIG inspection did not identify any immediate action by the NRC to address the generic concerns with Thermo-Lag 330-1. It was not until May 1991, after additional allegations regarding the performance of Thermo-Lag 330-1 were received by the NRC, that NRC inspectors made a fact finding visit to River Bend to review problems with the performance of Thermo-Lag 330-1.

Current status

In June 1991, in response to both the allegations and the problems identified at River Bend, the NRC established a Special Review Team to review Thermo-Lag 330-1 issues and make recommendations for their resolution. In August and December 1991, the NRC issued Information Notices (IN 91-47 and IN 91-79) which discussed the test failure of Thermo-Lag 330-1 at River Bend.

In December 1991, the NRC Vendor Inspection Branch (VIB) conducted its first inspection at TSI. This inspection disclosed problems with the TSI quality assurance

program and that ITL did not act as an independent testing laboratory when it witnessed TSI qualification tests of Thermo-Lag 330-1.

In January 1992, the Special Review Team completed its activities and in April 1992, issued a final report documenting its review of the performance of Thermo-Lag 330-1. One conclusion in the report was the fire resistance ratings and ampacity derating factors for the Thermo-Lag 330-1 fire barrier system are indeterminate.

The NRC is continuing to monitor the Thermo-Lag 330-1 testing being conducted by Comanche Peak. Further, the NRC is currently sponsoring testing of Thermo-Lag 330-1 at the National Institute of Standards and Technology. This testing was still ongoing at the time this report was prepared.

FINDINGS

Based on the information developed during this inspection, the OIG found that the NRC staff did not conduct an adequate review of fire endurance and ampacity derating information concerning the ability of the fire barrier material, Thermo-Lag 330-1. Had the staff conducted a thorough review of the test reports submitted by industry or verified the test procedures and test results reported by TSI, a number of problems with the test program and Thermo-Lag 330-1 would have been discovered.

An NRC vendor inspection at TSI at an earlier date would have determined there were problems with the TSI testing program. Further, it would have been discovered that the test reports were actually written by the vendor with no substantive verification that the data in the reports reflected the data recorded during the tests. Because these reviews and inspections were not conducted, it was not until 1992 that the NRC staff determined that the performance of Thermo-Lag 330-1 with respect to fire resistance ratings and ampacity derating was indeterminate.

In addition to the inadequate initial review process discussed above, the staff did not take any significant action between 1982 and 1991 when reports of problems with Thermo-Lag 330-1 were received. Our inspection disclosed seven instances in which NRC did not pursue reports of problems with Thermo-Lag 330-1.

BASIS AND SCOPE

This Office of the Inspector General (OIG) inspection was initiated in the spring of 1991, when the U.S. Nuclear Regulatory Commission (NRC), received allegations that questioned the adequacy of Thermo-Lag 330-1. Thermo-Lag 330-1 is a fire barrier material manufactured by Thermal Science, Inc. (TSI), St. Louis, Missouri. The NRC staff estimates that Thermo-Lag 330-1 is utilized in approximately 80-100 nuclear power plants. Thermo-Lag 330-1 was accepted by the NRC to protect redundant safe shutdown electrical circuits from fire. However, it has been alleged that the material does not provide the required level of protection with respect to fire endurance. Further, information was received that indicated that the ampacity derating figures for Thermo-Lag 330-1 are much higher than the reported figures. Ampacity derating figures are used in assuring the useful life of cables is achieved.

This OIG inspection addressed the adequacy of the NRC staff's acceptance and review of Thermo-Lag 330-1 as a fire barrier material for use in nuclear power plants. In addition, the inspection included a review of the staff's response to reports of problems with Thermo-Lag 330-1 that were received over a period of about 10 years. Our efforts involved interviews with utility officials at Comanche Peak, Susquehanna, Salem, Washington Nuclear Project, and Palo Verde. At each of these plants, we reviewed the documentation involving the decision to use Thermo-Lag 330-1. Interviews were also conducted with current and former NRC employees involved in the process of reviewing and accepting Thermo-Lag 330-1 for installation in nuclear power plants. We reviewed 12 years of correspondence among the utilities, vendors and the NRC involving the acceptance and installation of Thermo-Lag 330-1. We interviewed personnel from three fire testing laboratories, the Industrial Testing Laboratories, Inc. (ITL), and the manufacturer of a competing fire barrier material, Minnesota Mining and Manufacturing Company (3M). We reviewed reports of tests conducted at each of the laboratories. These tests also involved fire barrier materials other than Thermo-Lag 330-1.

In addition to this inspection effort, OIG, in conjunction with the Office of Investigations, is conducting an investigation involving the manufacturer of Thermo-Lag 330-1. OIG is also examining several allegations of NRC employee misconduct.

BACKGROUND

On March 22, 1975, a fire occurred at the Browns Ferry nuclear plant in Alabama. At that time, the nuclear reactors in Units 1 and 2 at Browns Ferry were operating, and a third unit was under construction. The fire began in the cable spreading room where technicians were testing for air leaks in the penetration seals between the cable spreading room and the reactor building. The fire caused minimal damage in the cable spreading room; however, it quickly spread through a seal into the Unit 1 reactor building located adjacent to the cable spreading room. The fire continued for about seven hours inside cable trays and conduits in the reactor building. Approximately 1600 electrical cables were damaged. Electrical shorts and grounding occurred as the insulation burned off the cables. This resulted in the loss of control power for much of the equipment, such as valves, pumps, and blowers. Although all of the emergency core cooling systems for Unit 1 were rendered inoperable, and portions of Unit 2 cooling systems were also affected, sufficient equipment remained operational to shut down the reactors and maintain the reactor cores in a cooled and safe condition. The damage to electric power and control systems also jeopardized the ability of the operators to monitor the status of the plant, including the reactor.

A Special Review Group (SRG) was established by the NRC shortly after the Browns Ferry fire to identify lessons learned and to make recommendations for the future. The SRG concluded that improvements, especially in the areas of fire prevention and fire control, should be made in most existing nuclear facilities. In its report, "Recommendations Related to Browns Ferry Fire" (NUREG-0050, February 1976), the SRG pointed out a lack of definitive criteria, codes, or standards related to fire prevention and fire protection in power plants. The review group also noted that the existing criteria covering separation of redundant electrical control circuits and power cables needed revision. The NRC developed technical guidance from the recommendations in the SRG report. In May 1976, the NRC issued guidance in Branch Technical Position (BTP) 9.5-1. This guidance, however, did not apply to nuclear facilities already in operation at that time. Guidance to operating plants was provided in July 1976 in Appendix A to the BTP.

By early 1980, most operating plants had implemented the guidelines in Appendix A, one of which was to protect redundant electrical systems required to achieve and maintain safe shutdown in the event of a fire. However, the fire protection program had some significant problems. Some licensees had expressed continuing disagreement with and refused to adopt recommendations relating to a number of issues. To resolve these contested issues, the Commission issued a fire protection rule for operating nuclear power plants. The new rule, contained in Title 10, Code of Federal Regulations, Part 50.48 (10 CFR 50.48) and 10 CFR 50, Appendix R, set out minimum fire protection requirements. These guidelines became effective on February 19, 1981, and applied to all plants licensed to operate before January 1, 1979.

As originally proposed to the public, all of the requirements in Appendix R would have applied to plants licensed to operate prior to January 1, 1979. Based on a review of public comments, the Commission determined that only three items in Appendix R were of such safety significance that they should apply to all plants. Accordingly, 10 CFR 50.48 requires that each nuclear power plant licensed to operate before January 1, 1979, meet the requirements of Appendix R, Sections III.G, III.J, and III.O. These sections deal with protection of safe shutdown capability, emergency lighting, and the reactor coolant pump lubrication system. Due to the safety significance of these items, the Commission approved the staff's recommendation that plants receiving operating licenses after December 31, 1978, must also satisfy the requirements of these sections.

The requirements of Section III.G, pertain to the protection of redundant safe shutdown electrical systems. The objective of this section is to ensure that at least one electrical circuit capable of achieving and maintaining the safe shutdown of the plant will remain free of damage and be available during and after a fire in the plant. Licensees can satisfy Section III.G by separating one train of electrical systems from its redundant train by: 1) a horizontal distance of 20 feet with no intervening combustibles, or 2) with fire-rated barriers. The fire resistance rating required of the barriers is either one hour or three hours depending on the other fire protection features provided in the fire area. The feature distinguishing the one hour from the three hour requirement is that an automatic sprinkler system must be installed when the one hour barrier is utilized.

For power plants unable to achieve a horizontal separation of 20 feet for the redundant safe shutdown systems, the installation of an acceptable fire barrier material was critical. However, in 1981 when Appendix R became effective, fire barrier materials that could be used to protect electrical circuits were still in the developmental stage. Before licensees could use a fire barrier material to satisfy the requirements of Appendix R, the NRC required that the products have a fire resistance rating of either one or three hours. The NRC and industry required that this rating be achieved by having a nationally recognized, fire testing laboratory subject the fire barrier material to a standard fire exposure test.

In 1981, the NRC began receiving requests from licensees for acceptance of Thermo-Lag 330-1 to satisfy the fire protection requirements in Appendix R. Since its initial acceptance in 1981, Thermo-Lag 330-1 has been the fire barrier material most extensively accepted by the NRC. It has been installed by many licensees to comply with the fire protection requirements of Section III.G of Appendix R. Thermo-Lag 330-1 has been installed in about 80-100 nuclear power plants to protect redundant safe shutdown electrical systems for both the one hour and three hour requirements of Section III.G of Appendix R.

Fire barrier qualification

When the NRC proposed 10 CFR 50.48 and Appendix R, the NRC stated that although nuclear power plants have few combustible materials and the chances of a fire are low, the potential consequences of fire are serious. For this reason, three hours was selected as the minimum fire resistance rating for fire barriers used to separate redundant safe shutdown electrical systems. The NRC considered a one hour barrier with an automatic fire detection and suppression system to be equivalent to a three hour fire barrier. Therefore, fire barriers relied upon to protect redundant safe shutdown systems need to have a fire resistance rating of either one hour or three hours.

The NRC adopted the standard fire test defined by the American Society for Testing and Materials (ASTM) in ASTM E-119, "Standards for Fire Resistance of Building Materials." The fire resistance rating is defined as "the time that materials or assemblies have withstood a fire exposure as established in accordance with the test procedure of Standard Methods of Fire Tests of Building Construction and Materials." ASTM E-119 also requires that a "hose stream" test be conducted. This consists of directing a stream of water onto the fire barrier immediately following the fire endurance test. The success criteria for the hose stream test would be that no opening in the barrier developed which permitted a projection of water to penetrate the fire barrier. Further, the NRC also required that the fire endurance qualification tests be conducted by nationally recognized, fire testing laboratories.

An NRC guidance document, Generic Letter (GL) 86-10, provided additional information on existing NRC fire barrier acceptance criteria. One criteria discussed was the requirement that the transmission of heat through the fire barrier during a fire endurance test shall not have been such as to raise the temperature to more than 325 degrees Fahrenheit inside the fire barrier. The 325 degree temperature criterion is used by the NRC because it functions to preserve the integrity of the cables and keep them free of fire damage.

Additional NRC criteria discussed in GL 86-10 required that the fire barrier specimen being exposed to the standard fire test duplicate what would be installed in the power plant. This is significant because construction variations between the test article and the installed assembly could substantially change the performance of the fire barrier. Consequently, this requirement applies to materials, methods of construction, the dimensions, and the configuration of the test barrier. GL 86-10 stated that licensees should either install barriers that replicate the configurations that were tested, or justify to the NRC that installed fire barriers that deviate from the tested configurations provide an equivalent level of protection.

Ampacity Derating Requirements

As electric current passes through a cable, heat is generated which raises the temperature of the cable. Ampacity is the electrical current-carrying capacity of a cable specified by the manufacturer. To avoid damage to cable insulation, the manufacturer's recommended temperature should not be exceeded during normal operations. When cables are placed in trays and conduits and enclosed in fire barrier material, the temperature of the cable insulation increases because the heat is retained by the barrier. Because electrical cable insulation is vulnerable to premature degradation when operating at abnormally high temperatures, the ampacity of the enclosed cables must be derated (lowered) to adjust for the insulating effect of the fire barrier material. To ensure that the expected life of electrical cables was not shortened, cable ampacity derating became an important consideration relative to the fire barrier material selected for installation in the nuclear power plants.

The "Protection Systems" section of 10 CFR 50.55a(h), requires that protection systems meet certain requirements for the ampacity derating of components. These requirements are set forth in the Institute of Electrical and Electronics Engineers Standard "Criteria For Protection Systems For Nuclear Power Generating Stations." Additionally, in accordance with NRC requirements, cable derating due to the use of fire retardant coatings must be considered by utilities during plant design or when design changes are made to existing electrical system configurations. The NRC electrical staff is responsible for reviewing cable derating to ensure compliance with accepted industry practice.

DETAILS

This OIG inspection was initiated upon receipt of allegations and other information indicating that Thermo-Lag 330-1 did not perform adequately with respect to fire endurance and ampacity derating. Because Thermo-Lag 330-1 is installed in about 80-100 nuclear power plants, the OIG inspection addressed the adequacy of the NRC staff's acceptance and review of Thermo-Lag 330-1 as a fire barrier material. Our inspection also involved a review of how the NRC staff has responded over the years to incidents that indicated problems with Thermo-Lag 330-1. OIG efforts included interviews with officials of utilities, vendors, fire testing laboratories, current and former NRC employees, and a review of documents extending over a period of nearly 12 years. The results of our inspection are presented in this section.

Fire endurance

To comply with the NRC fire protection requirements, utilities could separate redundant, safe shutdown circuits by at least 20 feet or protect the circuits with a fire barrier. The fire barrier material could have a one hour fire endurance rating if fire detection and automatic sprinkler systems were installed. If no sprinkler system were used, the barrier material must have a three hour fire endurance rating. In 1981, the practice of enclosing cable trays and conduits in nuclear power plants with fire barrier material was new; therefore, the availability of products for this purpose was limited. At this time, TSI began its efforts to adapt and qualify Thermo-Lag 330-1 for use in nuclear power plants.

Because Thermo-Lag 330-1 had no history of use in nuclear power plants to protect safe shutdown circuits, utilities proposing to install this fire barrier material sought NRC staff acceptance. Along with their proposals to use Thermo-Lag 330-1, the utilities submitted test reports and other documentation to qualify Thermo-Lag 330-1 as a fire barrier that met NRC fire protection requirements.

Beginning in 1981, the NRC received reports documenting fire tests of Thermo-Lag 330-1 that were conducted by TSI. These test reports were submitted to the NRC by utilities during the licensing process and by TSI. One example of this occurred in early 1982, when Washington Nuclear Project 2 (WNP-2) officials informed the NRC fire protection staff of a plan to have both one hour and three hour fire endurance tests conducted on cable trays enclosed with Thermo-Lag 330-1. In May and June 1982, the two tests were conducted by TSI in its St. Louis, Missouri facility. The tests were witnessed by ITL, also located in St. Louis, Missouri. WNP-2 provided the test reports to the NRC in August and October of that year. The test results indicated both one hour and three hour materials passed the fire endurance tests. NRC requirements state that a fire endurance test on barrier materials must be conducted by a nationally recognized, fire testing laboratory. As discussed in this OIG report, it has been recently determined that ITL was not a nationally recognized, fire testing laboratory. Nevertheless, the NRC staff

accepted ITL test reports. ITL test reports were used throughout the industry to qualify Thermo-Lag 330-1 for use in nuclear power plants.

Subsequent to initiation of this inspection, NRC technical staff reviewed a number of the reports of fire tests conducted by TSI and witnessed by ITL. These reviews disclosed that the TSI tests had not been performed in accordance with ASTM Standard E-119 as required by the NRC. The test furnace and temperature measuring devices used by TSI during the tests did not meet the requirements of ASTM E-119. In fact, although the NRC requires a full scale fire endurance test, the tests conducted at TSI are considered to be "small scale" tests. Additionally, the reports prepared to document the TSI tests did not contain sufficient detail to verify that some basic requirements of the ASTM E-119 test procedure, such as equipment calibration, were performed. Further, although the NRC required that the tested configurations duplicate the field installation, it was later determined that many of the configurations tested by TSI were not typical of field installations.

TSI fire endurance tests were reportedly validated by the presence of a representative from ITL, utility officials, and inspectors from American Nuclear Insurers (ANI). ANI is a property insurance organization which witnessed several of the TSI tests of Thermo-Lag 330-1 for utilities that planned to install Thermo-Lag 330-1. ANI witnessed the TSI tests to determine if Thermo-Lag 330-1 could provide acceptable protection of property for insurance purposes. OIG found that utility officials and ANI inspectors merely witnessed the conduct of fire tests. They did not inspect the test articles as they were being constructed by TSI employees to ensure all quality control and technical specifications were followed. They also could not verify that the tested articles were constructed the same as the ones described in the test reports. In fact, OIG was told that utility and ANI representatives were often absent during significant portions of the fire tests.

Although the ITL test reports state the fire tests were supervised and controlled entirely by ITL, it was determined that TSI controlled the tests and the ITL representative was present only as a witness to verify that a test was conducted. Quality control and construction of the test assemblies were completed by TSI with no independent verification by ITL. Further, even though the fire test reports were published with an ITL cover sheet, they were actually written by TSI and then signed by the President of ITL with no substantive verification that the data in the reports reflected the actual tests. Further, the ITL President related that in several instances he signed cover sheets for test reports without seeing the test reports.

Upon receipt of proposals to use Thermo-Lag 330-1, the NRC fire protection staff reviewed the written material to determine the acceptability of Thermo-Lag 330-1. When interviewed by the OIG, the NRC staff responsible for reviewing and accepting the proposals indicated that their managers told them that their review should consist of an examination of the documents submitted by the utilities. For example, when a utility

submitted a test report on a fire barrier material, the staff reviewed the test report to see that the report stated that the test was conducted in accordance with the NRC and industry fire endurance test standards and that the results were acceptable based on NRC criteria. The NRC managers of the fire protection staff advised OIG that the NRC review consisted of an audit of the paperwork submitted by the utilities. The NRC staff considered it the responsibility of the utilities to provide accurate information concerning the conduct of the qualification tests. The managers explained that utilities formally submitted information under oath. Consequently, the NRC did not find it necessary to observe any qualification tests of Thermo-Lag 330-1.

In 1981, Comanche Peak submitted a proposal to install Thermo-Lag 330-1 in Unit 1. The proposal was supported by a one hour fire endurance test conducted at Southwest Research Institute (SwRI). SwRI is a nationally recognized, fire testing laboratory. This is the only fire endurance test involving Thermo-Lag 330-1 conducted by a nationally recognized, fire testing laboratory that passed the NRC fire protection requirements. The Thermo-Lag 330-1 material that was tested at SwRI included an embedded layer of fiberglass. However, Comanche Peak decided not to install Thermo-Lag 330-1 with the fiberglass, and no other utility installed Thermo-Lag 330-1 with embedded fiberglass.

In May 1982, the NRC received from Susquehanna two TSI one hour test reports documenting TSI tests conducted in 1981 at the TSI facility. These reports were provided to the NRC by Susquehanna in an effort to support the installation of Thermo-Lag 330-1 and eliminate the need to conduct an additional test. However, in June 1982, the NRC fire protection staff rejected both TSI reports because they found the tests were not performed in accordance with adequate quality assurance procedures. Further, the tests conducted by TSI were "simulated" ASTM E-119 tests which differed from the required ASTM E-119 standard test. Although the NRC staff reviewers identified significant problems with these TSI reports, the OIG inspection found that within months, the NRC staff accepted a fire test which was conducted in the same furnace and under the same inadequate quality assurance procedures. The test was submitted by Washington Nuclear Project 2 as a basis for installing Thermo-Lag 330-1 in that plant.

In August 1982, the NRC fire protection reviewers also received fire endurance test results on one hour Thermo-Lag 330-1 conducted at SwRI for Susquehanna Unit 1. Unlike the one hour fire test conducted for WNP-2 at TSI and witnessed by ITL, the fire test conducted at SwRI did not pass the one hour Thermo-Lag 330-1 fire test. The test that failed was conducted at a nationally recognized, fire testing laboratory, while the test that passed was conducted by TSI and witnessed by an employee of ITL, a laboratory with no fire testing expertise. Therefore, during the same time period, the NRC fire protection staff received conflicting results of fire tests of one hour Thermo-Lag 330-1 conducted at different laboratories. The OIG inspection determined that the NRC reviewers did not pursue why one test passed and the other failed.

During the fall of 1982, TSI conducted two additional tests of Thermo-Lag 330-1. These were one and three hour fire endurance tests on cable trays containing a cable configuration that had applicability to many power plants. The tests were conducted in September and October 1982, at TSI with ITL witnessing the tests. As noted earlier, ITL did not possess any fire testing expertise. In both of these tests (ITL Reports 82-11-80 and 82-11-81), ITL represented that Thermo-Lag 330-1 passed the NRC requirements. Due to the generic nature of the test articles, these test reports were used throughout the nuclear power industry to qualify Thermo-Lag 330-1 with the NRC. Specific power plants that used these generic tests included Comanche Peak, Palo Verde, River Bend, Prairie Island, Callaway, and Susquehanna.

Once the NRC staff accepted Thermo-Lag 330-1 as a fire barrier that met NRC requirements, numerous proposals to use Thermo-Lag 330-1 were submitted by other utilities. For example, in the case of Palo Verde in early 1983, utility personnel verbally informed the NRC of their proposal to install Thermo-Lag 330-1 because it had been previously tested and the NRC had already accepted it. Palo Verde personnel told OIG that the NRC staff reviewer expressed no concerns with the use of Thermo-Lag 330-1; therefore, Palo Verde had no reason to conduct their own tests. Rather, Palo Verde used one of the generic tests conducted by TSI and witnessed by ITL as the basis for installing Thermo-Lag 330-1.

During this inspection, OIG became aware of about 25 tests of Thermo-Lag 330-1 that were conducted by TSI with ITL acting as a witness. ITL test reports prepared to document these tests indicated that with few exceptions, Thermo-Lag 330-1 met NRC fire protection requirements. Many of these tests conducted by TSI were used to qualify the installation of Thermo-Lag 330-1 at nuclear power plants.

Ampacity derating

As electric current passes through cables, heat is generated which raises the temperature of the cables. When cables are placed in cable trays and conduits, and enclosed in fire barrier material, the temperatures of the cables increase because heat is retained by the barrier. Electrical cables that operate in temperatures that are too high will deteriorate prematurely. Because of the negative effect of abnormally high temperatures, the electrical current-carrying capacity (ampacity) of the enclosed cables must be derated (lowered) to adjust for the insulating effect of the fire barrier material. Therefore, those fire barrier materials requiring the least derating would be most attractive to the user. As a result, cable ampacity derating became an important consideration relative to the fire barrier material selected for installation in nuclear power plants.

TSI conducted ampacity derating tests of Thermo-Lag 330-1. Originally, TSI reported to Comanche Peak that Thermo-Lag 330-1 would require a 10 percent ampacity derating. In 1982, TSI conducted a test with ITL as the witness and produced an ampacity derating figure of about 17 percent. As with the fire endurance test reports written by TSI and

signed by ITL, the TSI ampacity derating test reports stated that the tests were conducted under the supervision and total control of ITL. However, as noted earlier the ITL representatives told us they only witnessed the conduct of the tests, they did not control the tests, and they did not write the reports.

During this same time period, manufacturers of other fire barrier materials conducted ampacity derating tests and reported ampacity derating figures far higher than those reported by TSI. For example, Underwriters Laboratories (UL) conducted ampacity derating tests on the fire barrier material manufactured by Minnesota Mining and Manufacturing (3M) and reported ampacity derating figures of about 40 percent. Because TSI reported significantly lower derating figures compared to other manufacturers, Thermo-Lag 330-1 was an attractive choice for use by the utilities in reducing the negative effects of heat in the barriers.

In 1986, an engineering firm associated with the construction of the South Texas nuclear plant requested an ampacity derating test on Thermo-Lag 330-1. TSI arranged with UL to use its facility to conduct an ampacity derating test. The September 1986 tests at UL produced ampacity derating figures of about 31 percent for the three hour and about 28 percent for the one hour Thermo-Lag 330-1. These figures were significantly higher than the 10 per cent first reported by TSI.

The officials at UL told OIG that TSI refused to follow the UL ampacity derating testing procedure. After the TSI representatives left the UL facility, an additional ampacity derating test on Thermo-Lag 330-1 was conducted. This test followed the UL testing procedure and was conducted at UL's own expense. This additional test was conducted because UL believed the earlier tests and results were not valid. When the second UL test was conducted, the ampacity derating figures for Thermo-Lag 330-1 increased to nearly 40 percent for the three hour barrier and 36 percent for the one hour barrier. This information was not submitted to the NRC.

The NRC electrical staff was responsible for ensuring that utilities considered cable ampacity derating when designing and modifying their electrical systems. However, OIG found no evidence indicating the staff reviewed the ampacity derating tests on the Thermo-Lag 330-1 material even though it was being installed in the majority of nuclear power plants. The NRC staff explained it was the responsibility of the utilities to ensure that ampacity derating was considered when designing their electrical systems. Further, according to staff, if the utilities based their cable installation configurations on specific ampacity derating tests of fire barrier materials, it was the utilities responsibility to ensure the tests and the results were valid. The staff told OIG they had not reviewed ampacity derating test reports for fire barrier materials.

Indications of inadequate performance of Thermo-Lag 330-1 not addressed by the NRC

The NRC Vendor Inspection Branch (VIB) develops and conducts inspections of 1) vendors and licensee contractors who supply safety-related products and services to the nuclear industry, and 2) licensee procurement programs and interfaces with vendors. These inspections are often performed in response to allegations and reports of defective and substandard components and equipment in nuclear service or being offered for nuclear service. The VIB also determines the safety significance and generic implications of substandard vendor products. During its inquiry, OIG learned of instances over the past ten years which were reported to the NRC and which questioned the ability of Thermo-Lag 330-1 to perform as claimed by the manufacturer. However, our review of this information disclosed that the NRC staff did not effectively respond to these indicators. Several of these instances are discussed below:

Inadequate TSI test reports submitted by Susquehanna

In May 1982, during the NRC staff review of the Susquehanna fire protection program, Susquehanna submitted two TSI test reports involving one hour Thermo-Lag 330-1. The reason for this submittal was to assure the NRC that Thermo-Lag 330-1 was an acceptable fire barrier that performed in accordance with NRC requirements. In June 1982, after reviewing the two TSI test reports, the NRC fire protection staff rejected both and recommended that Susquehanna conduct a test at an approved testing laboratory. Among the reasons for the rejection, was the NRC reviewers findings that 1) TSI tests were not performed in accordance with adequate quality assurance procedures, and 2) the TSI tests were "simulated" ASTM E-119 tests, not the standard ASTM E-119 test as required by the NRC. However, in October 1982, the NRC staff accepted a test report from Washington Nuclear Project 2 that was conducted at TSI in the same manner and in the same furnace.

TSI tests documented in ITL test reports continue to be used to support the installation of Thermo-Lag 330-1 in nuclear power plants. These tests were witnessed by ITL, not a nationally recognized fire testing laboratory. OIG found no action by the NRC staff to address the fact that utilities were using TSI tests that were documented in ITL test reports to qualify their installation of Thermo-Lag 330-1. Nor was any effort made to resolve the fact that tests using the same TSI procedures were rejected and then accepted by the NRC.

Problems with ampacity derating identified during an NRC inspection

In 1985, an NRC inspection at Fort Calhoun nuclear power plant identified an apparent deficiency concerning the failure to verify the ampacity derating figures provided by the fire barrier material manufacturer, Minnesota Mining and Manufacturing Company (3M). A VIB inspection at 3M disclosed that the 3M ampacity figures were computer generated. The VIB inspector questioned the lack of documented 3M procedures to

ensure the computer generated derating figures were accurate. Because TSI also supplied ampacity derating information for Thermo-Lag 330-1 to a large segment of the nuclear industry, the NRC inspector asked TSI to provide the NRC with ampacity derating information. In April 1987, TSI forwarded to the VIB the UL report on the ampacity derating tests which had been conducted in September 1986. In addition, TSI provided two test reports and a TSI technical note on ampacity derating of Thermo-Lag 330-1. However, due to other priorities, the ampacity derating information provided by TSI was not reviewed by the NRC staff to determine if the TSI ampacity derating figures were adequately validated.

10 CFR Part 21 Report on ampacity derating

On October 2, 1986, TSI notified the NRC by mailgram that ampacity derating tests on Thermo-Lag 330-1 conducted at UL in September 1986 indicated ampacity derating figures that were significantly higher than those reported earlier by TSI. The earlier TSI figures were used by utilities to design electric power systems utilizing Thermo-Lag 330-1. The TSI mailgram was administratively recorded as a 10 CFR Part 21 Report by the NRC. Part 21 pertains to the reporting of defects to the NRC by the nuclear industry. At the time the report was received, NRC follow-up of 10 CFR Part 21 Reports was the responsibility of the Office for Analysis and Evaluation of Operational Data. This responsibility was later transferred to the VIB. In December 1990, the VIB closed the October 2, 1986, Part 21 Report without taking any action.

Comanche Peak report on new ampacity derating figures

In 1987, Comanche Peak responded to new information from TSI which established ampacity derating figures for Thermo-Lag 330-1 that were higher than the 10 percent originally reported by TSI and used in the initial cable sizing calculations at Comanche Peak. The new figures were 31 percent for single cable trays and 20 percent for single conduits enclosed in Thermo-Lag 330-1. On June 17, 1987, this information was verbally provided by Comanche Peak to the NRC resident inspector. On December 23, 1987, Comanche Peak provided a written report on this issue to the NRC. In its report to the NRC, Comanche Peak stated that failure to consider the additional derating of power cables due to Thermo-Lag 330-1 installation could cause the power cables to exceed the design temperature rating of the cables. Comanche Peak further noted that if left uncorrected, the higher ampacity derating could adversely affect the safety of plant operations. OIG found no NRC follow-up with TSI in order to obtain an explanation for the significant increase over the initial ampacity derating figures provided by TSI to Comanche Peak. Also, the NRC did not take any steps to ensure that other utilities were notified of the increased ampacity derating figures for Thermo-Lag 330-1.

Allegations regarding the performance of Thermo-Lag 330-1

On March 28, 1989, the NRC received an allegation that Thermo-Lag 330-1 gave off lethal gases when it burned. In support of this concern, the alleger provided the staff with information from a test of Thermo-Lag 330-1 documented in a May 1986 SwRI report. One month later, this issue became the subject of an Allegation Review Board meeting. During this meeting, it was decided to close the allegation without further action. In June 1989, the alleger was notified by letter of this decision.

OIG noted during its review of the staff's handling of the above allegation that in addition to concerns about toxicity, the alleger also informed the NRC in April 1989 about a fire endurance test of fire penetration seals for the River Bend nuclear power plant. This test had been conducted on June 18, 1985, at SwRI. The test involved Thermo-Lag 330-1 as a fire barrier used in conjunction with a fire penetration seal. The alleger provided the summary of the test which stated that the installation of Thermo-Lag 330-1 had no apparent effect on the outcome of the test because most of the Thermo-Lag 330-1 was totally gone when the assembly was removed from the furnace. In the letter, the alleger pointed out that the Thermo-Lag 330-1 had disintegrated during the test. The alleger also stated that he had heard the 3M company had experienced the same result when testing Thermo-Lag 330-1.

The alleger further related that River Bend was scheduled to conduct a full scale test of Thermo-Lag 330-1 at SwRI. OIG did not find any indication that the NRC staff conducted any inquiry into the information that Thermo-Lag 330-1 had been consumed in a fire test or that the staff attempted to obtain the results of the scheduled full scale test.

Problems with Thermo-Lag 330-1 at Comanche Peak

In 1989, NRC Region IV was informed that panels of one hour Thermo-Lag 330-1 were arriving at Comanche Peak, from TSI, that measured less than the required thickness. To provide one hour protection for cable trays in the event of a fire, Thermo-Lag 330-1 was required to be one half inch thick. Subsequently, Comanche Peak management discussed the situation with TSI. In a July 13, 1990, letter to the NRC, Comanche Peak explained that the behavior of Thermo-Lag 330-1 under fire conditions is dependent on the density of the product and not on the thickness. Therefore, in conjunction with a TSI recommendation, Comanche Peak developed new receipt inspection criteria based on panel weight instead of thickness. Comanche Peak also informed the NRC that TSI's quality assurance program required that Thermo-Lag 330-1 prefabricated panels be subjected to detailed thickness measurements prior to shipment to the plant. Comanche Peak assured the NRC that the TSI panel fabrication and quality control inspection methodology had remained essentially unchanged since TSI began production of prefabricated panels in the early 1980's. After reviewing the Comanche Peak July 13,

1990, letter and without further inquiry of TSI or Comanche Peak, Region IV accepted the resolution of the matter provided by Comanche Peak and TSI and closed this issue.

During this inspection, OIG learned from the NRC and National Institute of Standards and Technology staff that the Comanche Peak quality control practice of checking weights was not an effective inspection method for Thermo-Lag 330-1 panels. Additionally, in December 1991, during the only NRC VIB inspection of TSI, the NRC found that the TSI quality assurance program did not specify a requirement for measuring minimum thickness of Thermo-Lag 330-1 panels fabricated at TSI. This finding was not consistent with the explanation given to NRC Region IV by Comanche Peak personnel and was relied on by Region IV to close the issue at that time. The problems at Comanche Peak provided another opportunity for the NRC to inquire into the performance of TSI and Thermo-Lag 330-1 that was not pursued.

Concerns about the performance of Thermo-Lag 330-1 at River Bend

In December 1989, the River Bend nuclear power plant submitted an Informational Report to the NRC regarding an October 1989 test of Thermo-Lag 330-1. The fire test was conducted at SwRI, a nationally recognized, fire testing laboratory, to verify Thermo-Lag 330-1 performance and to compare the three hour rated Thermo-Lag 330-1 with the product from a competing company. Both fire barriers were applied to 30 inch wide aluminum cable trays. The Informational Report documented that at approximately 41 minutes into the three hour test, the Thermo-Lag 330-1 covering the bottom of the cable tray fell off. As the test continued, temperatures inside the cable tray enclosure increased with a loss of circuit integrity at 47 minutes.

As a result, River Bend conducted an investigation and identified several generic issues with Thermo-Lag 330-1 that were outlined in the Informational Report. The Informational Report noted that prior to the River Bend test of a 30 inch cable tray, the maximum size previously tested was 12 inches. However, cable trays of a larger size than 12 inches are used in power plants. The OIG inspection did not identify any immediate action by the NRC to address the generic concerns with Thermo-Lag 330-1. It was not until May 1991, after additional allegations regarding the performance of Thermo-Lag 330-1 were received by the NRC, that NRC inspectors made a fact finding visit to River Bend to review problems with the performance of Thermo-Lag 330-1.

Current status

In February 1991, the NRC received allegations from a confidential alleger that Thermo-Lag 330-1 did not provide the protection for electrical cables required by NRC and as claimed by the vendor.

In May 1991, the NRC staff visited River Bend to review with utility officials installation discrepancies and failed fire endurance tests. These problems were first reported to the

NRC by the utility in April 1989. As a result of this visit, the staff concluded that a generic concern existed with respect to the abilities of Thermo-Lag 330-1 to protect 30 inch cable trays. In June 1991, in response to both the allegations and the problems identified at River Bend, the NRC established a Special Review Team to review Thermo-Lag 330-1 issues and make recommendations for their resolution. In August and December 1991, the NRC issued Information Notices (IN 91-47 and IN 91-79) which discussed the test failure of Thermo-Lag 330-1 at River Bend and problems that could result from improperly installing Thermo-Lag 330-1.

In December 1991, the VIB conducted its first inspection at TSI. This inspection disclosed problems with the TSI quality assurance program and that ITL did not act as an independent testing laboratory when it witnessed TSI qualification tests of Thermo-Lag 330-1.

In January 1992, the Special Review Team completed its activities and in April 1992, issued a final report documenting its review of the performance of Thermo-Lag 330-1. One conclusion in the report was that the fire resistance ratings and ampacity derating factors for the Thermo-Lag 330-1 fire barrier system are "indeterminate." Additionally, as a result of concerns developed during the review by the Special Review Team, the NRC prepared a draft Generic Letter in February 1992. This Generic Letter would require licensees to provide information to verify that their Thermo-Lag 330-1 fire barrier installations comply with NRC requirements. As of July 31, 1992, the NRC had not finalized the Generic Letter.

On June 24, 1992, NRC Bulletin 92-01 was issued as a result of further fire endurance tests of Thermo-Lag 330-1 at Omega Point Laboratories. These tests were conducted by Comanche Peak to qualify their Thermo-Lag 330-1 fire barrier system. The testing resulted in failures of several Thermo-Lag 330-1 fire barrier systems that were designed to duplicate actual plant configurations. The bulletin stated that the NRC considered these tests to be failures of the Thermo-Lag 330-1 fire barrier system. In this bulletin, the NRC concluded that the one hour and three hour Thermo-Lag 330-1 preformed assemblies installed on small conduits and on cable trays wider than 14 inches did not provide the level of safety required by the NRC. The bulletin required that where applicable, utilities implement appropriate compensatory measures. On June 23, 1992, in conjunction with the bulletin, the NRC issued Information Notice 92-46 which informed the industry of the findings of the Special Review Team and the results of the fire endurance tests conducted at Omega Point.

During the week of July 13-17, 1992, pursuant to a contract between NRC and the National Institute of Standards and Technology, tests of Thermo-Lag 330-1 one and three hour fire barriers were conducted. Both tests failed the NRC fire protection requirements. On July 27, 1992, the NRC issued Information Notice 92-55 addressing the results of these tests. Additionally, as a result of these efforts, the NRC staff has become concerned that Thermo-Lag 330-1 is a combustible material. The staff is

reviewing this matter of combustibility in light of the fact that Thermo-Lag 330-1 has been used in areas of nuclear power plants that were required to be free of combustibles.

NRC efforts are also underway to assure that accurate ampacity derating figures for Thermo-Lag 330-1 are being used by the nuclear industry. The life of cables enclosed in Thermo-Lag 330-1 may have been shortened, and the utilities may not be aware of the extent of this problem since they assumed the ampacity figures initially provided by TSI were accurate.

FINDINGS

Based on the information developed during this inspection, we found that the NRC staff did not conduct an adequate review of fire endurance and ampacity derating information concerning the ability of the fire barrier material, Thermo-Lag 330-1. Had the staff conducted a thorough review of the test reports submitted by industry or verified the test procedures and test results reported by TSI, a number of problems with the test program and Thermo-Lag 330-1 would have been discovered. For example, the staff would have found that the test furnace at TSI was not adequate to conduct the required standard fire endurance test; however, it has continued to be used since 1981. Also, the staff would have discovered that the quality assurance procedures at the TSI test facility were not adequate.

Identification of such problems could have resulted in an NRC vendor inspection at TSI. The vendor inspection would have determined there were problems with the TSI testing program and that the fire endurance and ampacity derating tests were not conducted, as required, by a nationally recognized testing laboratory. Further, it would have been discovered that the test reports were actually written by the vendor with no substantive verification that the data in the reports reflected the data recorded during the tests. Because these reviews and inspections were not conducted, it was not until 1992 during the conduct of reviews by the NRC Special Review Team and the OIG/OI investigative taskforce, that the staff determined that the performance of Thermo-Lag 330-1 with respect to fire resistance ratings and ampacity derating was indeterminate.

In addition to the inadequate initial review process discussed above, the staff did not take any significant action between 1982 and 1991 when reports of problems with Thermo-Lag 330-1 were received. Our inspection disclosed seven instances in which the NRC did not pursue reports of problems with Thermo-Lag 330-1.

Exhibit FP No. 3

Exhibit FP No. 3

Environment and Energy Daily

October 4, 2001

NUCLEAR SECURITY LANGUAGE FOR ANTI-TERRORISM BILL APPROVED

BYLINE: Suzanne Struglinski

SECTION: NUCLEAR POLICY; Vol. 10, No. 9

LENGTH: 1011 words

The House Energy and Commerce Committee on Wednesday approved language concerning **Nuclear Regulatory Commission** security and bioterrorism that could be part of a future, larger anti-terrorism bill. However, negotiations are expected to continue prior to floor action on several possible amendments submitted by Rep. Ed Markey (D-Mass.).

Rep. Joe Barton (R-Texas), Energy and Air Quality Subcommittee chairman, submitted the **NRC** language, which was approved by voice vote. The language authorizes guards at **NRC** licensed facilities to carry and use weapons to protect the facilities or prevent theft of special nuclear materials. If passed into law, guards would be able to carry firearms and make arrests without a warrant under specific circumstances. Barton said that currently, only Energy Department security forces now have that ability even though **NRC** facilities handle nuclear material. Also, **NRC** would be allowed to regulate dangerous weapon use on any facility licensed or certified by it, meaning public or private property.

"This change ensures that the full range of facilities regulated by the commission are subject to the statutory provisions prohibiting the introduction of weapons or other dangerous instruments, providing an additional measure of security for materials which could be subject to theft or sabotage," Barton said.

The language -- which is intended to be incorporated into a larger anti-terrorism bill -- also extends laws prohibiting sabotage or attempted sabotage of nuclear facilities to include nuclear waste treatment and disposal facilities and nuclear fabrication facilities. Barton pointed out that this language was included in the **NRC** reauthorization language that passed last Congress but did not become law.

Rep. Cliff Stearns (R-Fla.) offered an amendment raising penalties for attempted nuclear plant sabotage or threats that cause damage to public health or safety to $1 million and a prison term of up to life in prison without parole. The

amendment also passed by voice vote.

Rep. Heather Wilson (R-N.M.) offered an amendment to conduct a study to asses the vulnerabilities of nuclear power plants to potential terrorist attacks. She wants the study to include an assessment of the plant's design, to identify long-term and short-term protection measures, assess physical, cyber, biochemical and other terrorist threats, and recommend additional studies as needed. The study would be due to Congress 90 days after enactment. The amendment was approved by voice vote.

Markey submitted a similar amendment, however his asks for an NRC rulemaking within a year of enactment revising the design basis threat and associated regulations. He wants regulations issued specifically taking into account a list of nine items, including the Sept. 11. attack, potential for attacks, potential suicide attacks and fire threats. NRC is to meet with the secretary of Defense, director of Central Intelligence, director of the Federal Bureau of Investigation, national security adviser, director of Homeland Security and other appropriate officials before completing the rulemaking.

"The threat is real, it's serious and it requires study and action," Markey said.

Committee ranking member John Dingell (D-Mich.) supported Markey's amendment saying the rulemaking has more clout than just a review and that it sets forth what they need to look at.

"You can't count on [NRC Chairman Richard] Meserve and his bunch of sleepyheads to complete [a review]," Dingell said.

Tauzin also read a letter from NRC alluding to plans to review security and vulnerabilities anyway.

Markey also proposed an amendment that would allow the president to deploy armed forces to the national guard to defend NRC licenses facilities should another attack occur. Barton objected to the amendment saying the president already has that ability and that the bill was not necessary. However, he later withdrew his objection.

"What the hay? Congress does a lot of things that are unnecessary," Barton said.

Markey later withdrew the amendment after Tauzin said he would confer with the House Armed Services Committee to hammer out potential jurisdictional problems with the bill.

Markey's third amendment was designed to allow NRC to establish a system looking at the transportation of nuclear waste. Wilson objected to the amendment expressing concern over a possible limitation on Energy Department, National Nuclear Security Administration or Defense Department responsibilities. Barton said the language may also affect medical radioactive waste, such as that associated with cancer treatments. Markey also withdrew this amendment after Tauzin said the committee would examine the language to see how the bill could be limited only to NRC.

Tauzin and several other members, also acknowledged that a closed meeting with Meserve and other officials taking place later Wednesday afternoon could clear up some questions surrounding the provisions. Markey eventually withdrew the amendment. Tauzin said language similar to the amendment could be introduced when the bill goes to the floor.

The bioterrorism provisions, also approved Wednesday, "close loopholes and stiffen penalties for the possession of substances such as anthrax and other deadly biological agents and toxins that could be used for a bioterrorist attack," Tauzin said.

Provisions for the bioterrorism and NRC language were derived from Attorney General John Ashcroft's anti-terrorism proposal to Congress.

Tauzin said the committee will continue a broader investigation into ways to secure the country's energy, telecommunications, health and other critical infrastructures.

THURSDAY'S AGENDA

The Subcommittee on Energy and Air Quality plans to hold a markup at 9:30 a.m., Thursday, in 2123 Rayburn looking at H.R. 2983, the Price-Anderson Reauthorization Act of 2001, and H.Res. 250, a resolution urging the secretary of Energy to fill the Strategic Petroleum Reserve.

LOAD-DATE: October 3, 2001

LANGUAGE: ENGLISH

Exhibit FP no. 4 omitted

Exhibit FP No. 5

Exhibit FP No. 5

Entergy

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Fred Dacimo
Site Vice President
Administration

July 24, 2006

Re: Indian Point Unit No. 3
Docket No. 50-286
NL-06-078

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

SUBJECT: Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

References:

1) NRC Information Notice 2005-07, "Results of HEMYC Electrical Raceway Fire Barrier System Full Scale Fire Testing," April 1, 2005

2) NYPA Letter, J. C. Brons to S. A. Varga (NRC), "Appendix R Fire Protection Program," August 16, 1984

3) NYPA Letter, J. C. Brons to S. A. Varga (NRC), "Information to Support the Evaluation of IP3 to 10 CFR 50.48 and Appendix R to 10 CFR 50," September 19, 1985

4) NRC Letter and SER, S. A. Varga to J. C. Brons (NYPA), "Indian Point 3 Nuclear Power Plant - Exemption From Certain Requirements of Section III.G and III.J of Appendix R to 10 CFR Part 50," January 7, 1987

5) IPEC Letter NL-06-060, F. Dacimo to Document Control Desk, "Response to Generic Letter 2006-03 (Potentially Nonconforming Hemyc and MT Fire Barrier Configurations)," June 8, 2006

Dear Sir or Madam:

NRC Information Notice (IN) 2005-07 (Reference 1) notified licensees of potential performance concerns associated with the one-hour rated Hemyc electrical raceway fire barrier system (ERFBS), indicating that the system may be incapable of fulfilling the stated one-hour fire resistance rating when tested in accordance with Generic Letter 86-10, Supplement 1 criteria. Indian Point Unit No. 3 (IP3) utilizes the one-hour rated Hemyc

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ERFBS that is the subject of IN 2005-07 in two areas of the plant. In a Safety Evaluation Report (SER) dated January 7, 1987 (Reference 4) , the Staff granted a number of exemptions from specific requirements of 10 CFR 50, Appendix R, which included these two plant areas. Entergy has reviewed the Hemyc fire test results provided by the NRC in IN 2005-07 and has determined that it is necessary to revise the fire resistance rating of the Hemyc ERFBS configurations credited in two of the exemptions. The two affected exemptions are those applicable to Fire Area PAB-2 in the Primary Auxiliary Building, and Fire Area ETN-4 in the Electrical Tunnels and Electrical Penetration Areas.

In accordance with 10 CFR 50.12, the purpose of this letter is to request revision of the January 7, 1987 SER to reflect that the installed Hemyc ERFBS configurations provide a 30-minute fire resistance rating, in lieu of the previously stated one-hour fire resistance rating. The requests for the exemptions granted by the January 7, 1987 SER were docketed in NYPA Letters dated August 16, 1984 (Reference 2) and September 19, 1985 (Reference 3). Based on a review of these letters and of the NRC test results, it is Entergy's position that a Hemyc ERFBS fire resistance rating of 30 minutes will provide sufficient protection for the affected raceways, with adequate margin, to continue to meet the intent of the original requests for exemption and the conclusions presented in the January 7, 1987 SER. This evaluation is summarized in Attachment 1.

As documented in Attachment 1, it is Entergy's conclusion that the revised fire resistance rating of the Hemyc ERFBS does not reflect a reduction in overall fire safety, and presents no added challenge to the credited post-fire safe-shutdown capability. The remainder of the credited fire protection features, the fire hazards and ignition sources, fire brigade and operator response to fire events, and the credited post-fire safe-shutdown capability remain materially unchanged from the configuration as originally described in the NYPA letters and as credited in the January 7, 1987 SER.

Entergy has reviewed the as-built configurations of the Hemyc ERFBS installed at IP3 against the results of the NRC Hemyc fire test program as referenced by IN 2005-07. This review has determined that the installed ERFBS can be expected to afford a thermal protection rating of at least 30 minutes, contingent upon the installation of a modification to augment raceway support protection and to install over-banding of certain enclosures. A commitment to install these modifications is contained in our response to Generic Letter 2006-03 (Reference 5). The conclusions from the engineering evaluation are also summarized in Attachment 1.

There are no new commitments contained in this letter. If you have any questions or require additional information, please contact Mr. Patric W. Conroy at 914-734-6668.

Sincerely,

For - Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachment 1: Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

cc: Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. John P. Boska, Senior Project Manager, NRC NRR DORL
NRC Resident Inspectors Office, Indian Point Energy Center
Mr. Paul Eddy, New York State Department of Public Service
Mr. Peter R. Smith, NYSERDA

ATTACHMENT 1 to NL-06-078

Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

Entergy Nuclear Operations, Inc.
Indian Point Nuclear Generating Unit No. 3
Docket No. 50-286

Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

1.0 INTRODUCTION

The Indian Point Unit No. 3 (IP3) electrical raceways provided with Hemyc ERFBS protection consist of several conduits, cable trays, and a box-type enclosure. The locations of the Hemyc ERFBS installations are illustrated by Figures 1 through 4.

To support the request for revision to the two exemptions applicable to Fire Areas ETN-4 (Electrical Tunnels and Electrical Penetration Areas) and PAB-2 (Component Cooling Pump Area) contained in the January 7, 1987 SER (Reference 8.1), this attachment:

- Discusses the licensing basis for the one-hour Hemyc electrical raceway fire barrier system (ERFBS) (Section 2.0);
- Discusses the fire hazards, combustible controls, and fire protection features of the areas (Section 3.0);
- Evaluates the acceptability of a 30-minute rating considering the current fire hazards and fire protection features in the areas (Section 4.0);
- Presents a summary description of the installed one-hour Hemyc ERFBS configurations, and of the evaluation of the results of the NRC Hemyc fire test program (Reference 8.11) (Section 5.0).

As documented in Reference 8.11, the NRC Hemyc test specimens provided acceptable thermal performance for a period of at least 30 minutes, or the results provided insight into the observed failure mechanisms. Further, each of the installed IP3 Hemyc configurations is bounded by one or more of the NRC test specimens, or is subject to a planned modification based on the insights learned from the NRC test program. As determined in Reference 8.11, the Hemyc ERFBS at IP3 can be expected to provide a fire resistance rating of a minimum of 30 minutes, consistent with ASTM E 119 temperature rise acceptance criteria. A fire resistance rating of 30 minutes will provide adequate protection for the affected IP3 safe-shutdown raceways, in consideration of the additional mitigating factors of low fire loading and active and passive fire protection features installed in each of the two affected plant areas.

2.0 EXISTING LICENSING BASIS FOR ONE-HOUR ERFBS IN AFFECTED PLANT AREAS

2.1 Electrical Tunnels and Penetration Areas: Fire Area ETN-4: Upper and Lower Electrical Tunnels (Fire Zones 7A and 60A, respectively) and Upper Penetration Area (Fire Zone 73A)

By SER dated February 2, 1984 (Reference 8.4), the Staff approved an exemption from the Appendix R Section III.G separation requirements, to the extent that redundant safe-shutdown systems are not separated by more than 20 feet free of intervening combustibles or fire hazards, and that redundant safe-shutdown systems are not separated by a one-hour rated fire barrier in an area which is protected by automatic fire detection and suppression systems. The bases for this exemption included the existing separation between redundant safe-shutdown trains, minimal fire hazards, flame-retardant characteristics of cable insulation, and the installed active and passive fire protection features.

Following a comprehensive reassessment of the IP3 Appendix R compliance basis, by letters dated August 16, 1984 and September 19, 1985 (References 8.3 and 8.2, respectively), NYPA informed the NRC of the need for additional separation measures to be installed in Fire Area ETN-4. These measures included the installation of one-hour rated fire wrap on several safe-shutdown raceways. By SER dated January 7, 1987 (Reference 8.1), the Staff acknowledged this clarification and the addition of one-hour rated fire wrap, and confirmed the continued validity of the exemption granted by the February 2, 1984 SER (Reference 8.4).

2.2 Primary Auxiliary Building, Fire Area PAB-2: Fire Zone 1, 41' Elevation CCW Pump Area

In the SER dated January 7, 1987 (Reference 8.1), the Staff approved an exemption from the Section III.G separation requirements for this fire zone, to the extent that an automatic suppression system has not been provided, and redundant safe-shutdown systems are not separated by more than 20 feet free of intervening combustibles. The bases for this exemption included the existing separation between redundant safe-shutdown trains, low fire loading, a fire detection system, manual hose stations and portable extinguishers, a partial height noncombustible barrier designed to protect the CCW pump against radiant heat from a fire, and a one-hour fire rated cable wrap around the normal power feed conduit to the 33 CCW pump.

3.0 FIRE HAZARDS, COMBUSTIBLE CONTROLS, AND FIRE PROTECTION FEATURES IN FIRE AREAS ETN-4 AND PAB-2

3.1 Evaluation of Hazards/Ignition Sources and Combustible Controls

The fire hazards and ignition sources in Fire Areas ETN-4 and PAB-2 remain materially unchanged from the characteristics of these areas as described in the SERs dated February 2, 1984 (Reference 8.4) and January 7, 1987 (Reference 8.1), and the NYPA correspondence referenced therein, as applicable to the specific fire zone.

Transient combustible and hot work controls have been enhanced since the transition from NYPA to Entergy operation of IP3, with the issuance of procedures EN-DC-127, "Control of Hot Work and Ignition Sources" (Reference 8.8) and ENN-DC-161, "Transient Combustible Program" (Reference 8.9). Notably, per Transient Combustible Program procedure ENN-DC-161, Fire Areas ETN-4 and PAB-2 are designated as "Level 2" combustible control areas, which constrains transient combustibles to moderate quantities. Any planned introduction of more than the allowable quantities of combustibles into these areas requires a prior review by Fire Protection Engineering, which will include the definition of additional protective/compensatory measures as determined to be applicable. In addition, per procedure EN-DC-127, any planned hot work in IP3 Fire Areas ETN-4 or PAB-2 requires the prior review and approval of Fire Protection Engineering. This constraint provides assurance that hazards and potential effects consistently receive proper prior evaluation, and that compensatory measures, as applicable, are adequately defined in advance of the hot work activity.

The administrative controls imposed by ENN-DC-161 and the structured Fire Protection Engineering review of planned hot work activities per EN-DC-127 provide additional assurance that the potential for, and potential effects of, significant floor-based transient combustible fires is sharply limited.

3.2 Active Protection: Fire Detection and Suppression Features

The installed fire detection systems and automatic and manual fire suppression features in the affected zones of Fire Areas ETN-4 and PAB-2 remain functionally unchanged from those described in SERs dated February 2, 1984 (Reference 8.4) and January 7, 1987 (Reference 8.1), and the NYPA correspondence referenced therein, as applicable. Preaction automatic water spray suppression is provided in ETN-4 for protection of cable trays; manual suppression capabilities are provided in both Fire Areas ETN-4 and PAB-2, in the form of accessible fire hose stations and portable fire extinguishers.

3.3 Passive Fire Protection Features

The installed passive fire protection features (fire barriers and penetration seal systems) in Fire Areas ETN-4 and PAB-2 remain functionally unchanged from those described in SERs dated February 2, 1984 (Reference 8.4) and January 7, 1987 (Reference 8.1), and the NYPA correspondence referenced therein, as applicable.

3.4 Transient Combustible Control and FP Equipment Operating History

A review of IP3 condition reports for the period beginning with Entergy ownership through the present indicated that no significant fire protection related deficiencies applicable to Fire Zones 1, 7A, 60A, or 73A were identified during this time period. Topics searched included fire barriers, ERFBS, fire suppression, fire detection, and housekeeping/combustible loading. Hence, there is reasonable assurance that the design and operational controls (as described above) in place since the transition to Entergy operation of IP3 have maintained the fire protection defense-in-depth measures consistent with the IP3 fire protection licensing basis.

4.0 ADEQUACY OF A 30-MINUTE ERFBS TO PROTECT SAFE-SHUTDOWN CABLES

4.1 Fire Area ETN-4, Fire Zones 7A, 60A, and 73A

As described in the SER dated February 2, 1984 (Reference 8.4), the fire hazards in the affected zones of this area are small. As given by Reference 8.7, the calculated fire severity in Fire Area ETN-4 is less than 60 minutes, of which less than one minute of fire severity is attributable to the expected transient fire loading. The balance of the combustible inventory is predominantly asbestos-jacketed, flame-retardant electrical cable insulation. The flame-retardant characteristics of the principal combustible ensure that fire will not propagate along the cables to any significant degree, thereby limiting the rate of development and damage incurred by credible fires. As the credible fire scenarios involve floor-based transient combustibles, the impact of such a fire, at any location within the area, is expected to be slight, and insufficient to involve substantial quantities of the predominant fixed combustibles (the flame-retardant cables in trays). In addition, the fire detection, automatic cable tray fire suppression system, and manual fire suppression features provide further assurance that fire damage will be limited in scope and severity. Therefore, based on the current Fire Hazards Analysis, an ERFBS with a 30-minute fire resistance rating is adequate to protect the safe-shutdown cables in this area.

Based on a review of the fire zones in this area using the guidance and tools of NUREG-1805 (Reference 8.10), it was found that the credible fire challenge would be less severe than that imposed by an ASTM E 119 fire exposure. Further, with the installed smoke detection system and the preaction water spray system for the cable trays in the area, the credible fire challenge in the affected zones of Fire Area ETN-4 can be expected to result in a temperature profile that is substantially less severe than that of the ASTM E 119 time-temperature curve. Therefore, based on the insights using NUREG-1805 guidance and tools, the expected fire effects in this Fire Area will not challenge a Hemyc ERFBS installation that has a fire resistance rating of 30 minutes.

4.2 Fire Area PAB-2, Fire Zone 1

As described in the SER dated January 7, 1987 (Reference 8.1), the fire load in this area is low. As given by Reference 8.7, the calculated fire severity in Fire Area PAB-2, Fire Zone 1 is less than 10 minutes. The small quantity of combustible materials (e.g., CCW pump lubricating oil or transient materials) would be expected to result in a credible fire which is localized, with a low aggregate heat release, and no challenge to redundant safe-shutdown cables or components caused by radiant or convective energy. The installed fire detection system would ensure timely detection, enable prompt manual suppression of the fire, and provide assurance that any fire damage will be limited in scope and severity. Therefore, the credible fire challenge can be expected to result in a temperature profile less severe than that of the ASTM E 119 time-temperature curve.

Hence, an ERFBS capable of providing at least 30 minutes of protection for the enclosed cables when tested in accordance with ASTM E 119 will provide adequate protection for the safe-shutdown cables in this area, given the hazards in the area and the active fire protection features.

5.0 EVALUATION OF IP3-SPECIFIC HEMYC ERFBS VERSUS NRC-TESTED CONFIGURATIONS

The installed IP3 Hemyc ERFBS is summarized as follows:

- Two 4" rigid steel conduits, each with a cable percent fill of approximately 30%. The two 4" rigid steel conduits are protected with direct-attached 2" thick Hemyc blanket wrap.

- Seven 18" cable tray sections, with a cable percent fill in these trays ranging from approximately 10% to 25%. Also wrapped are two 24" cable tray sections, each with a cable percent fill of approximately 50%. All cable trays

are wrapped using 1-1/2" thick Hemyc blanket with a 2" air gap between the blanket and the protected raceway.

- Box-type enclosure at containment electrical penetrations H19/H20, consisting of 2" thick Hemyc blanket directly attached to the enclosure.

The IP3 Hemyc ERFBS configurations have been compared to the size, orientation, materials, methods of construction, and thermal performance of the test specimens of References 8.5 and 8.6 in an engineering evaluation (Reference 8.11). The detailed thermal performance results of the NRC Hemyc fire tests indicated that several of the tested configurations provided at least 30 minutes of protection for the enclosed safe-shutdown cables, or provided insights into the failure mechanisms that occurred during testing. The engineering evaluation compares the details of these tested configurations with the details of the IP3 Hemyc ERFBS configurations. This evaluation establishes that the IP3 Hemyc ERFBS configurations are sufficiently comparable to the NRC-tested configurations, with minor enhancements to several IP3 configurations, which include the need to augment the ERFBS on raceway supports and to install additional over-banding on certain enclosures. Pending implementation of those modifications to the affected configurations, all of the IP3 Hemyc ERFBS configurations can be expected to provide a fire resistance capability of at least 30 minutes for the enclosed safe-shutdown cables.

6.0 REGULATORY ANALYSIS

10 CFR 50.12(a) states that the Commission may grant exemptions from the requirements of the regulations contained in 10 CFR 50 which are:

(1) Authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security; and,

(2) If special circumstances are present.

This request for revision of existing exemptions meets the criteria set forth in 10 CFR 50.12, *as discussed herein.*

6.1 The requested exemption is authorized by law

10 CFR 50.12(a) authorizes the NRC to grant exemptions from its regulations, and no law is known that precludes the NRC from granting the requested revision to the existing exemptions.

6.2 The requested exemption does not present an undue risk to the public health and safety

The Hemyc ERFBS configurations installed in IP3 Fire Areas ETN-4 and PAB-2 will provide a fire resistance capability of at least 30 minutes, as discussed in Section 5.0. The minimal fire hazards and ignition sources, combined with the nature of the fire hazards in the areas, the active and passive fire protection features, and the controls on transient combustibles and ignition sources, as discussed in Section 3.0, provide assurance that the credible fire challenge to the IP3 Hemyc ERFBS will be substantially less than that of an equivalent ASTM E 119 30-minute fire exposure. Therefore, as discussed in Section 4.0, the installed ERFBS can be expected to provide adequate protection for the affected safe-shutdown raceways and enclosed cables.

Therefore, given the existing level of fire protection defense in depth, combined with the minimal fire challenge presented by the credible fire scenarios in these areas, and the favorable FP equipment operating history, the change in credited ERFBS fire resistance rating from one hour to 30 minutes will not degrade the effectiveness of the IP3 fire protection program, nor will it challenge the credited post-fire safe-shutdown capability. Based on the determination that safe shutdown in the event of a fire can be achieved and maintained with less than a one-hour fire resistance rating, the requested revision to the existing exemptions does not present an undue risk to the public health and safety.

6.3 The requested exemption is consistent with the common defense and security

The requested revision to the existing exemptions is not directly related to and should not adversely impact the common defense and security.

6.4 Special circumstances are present – underlying purpose of the rule

10 CFR 50.12(a) requires that special circumstance be present in order for the Commission to consider granting an exemption. Per 10 CFR 50.12(a)(2)(ii), one special circumstance is that application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule.

The underlying purpose of 10 CFR 50, Appendix R, Section III.G is to provide reasonable assurance that at least one means of achieving and maintaining safe shutdown conditions will remain available during and after any postulated fire. For the areas containing the Hemyc ERFBS installations, the credible fire challenge to the IP3 Hemyc ERFBS due to any postulated fire will be substantially less than that of an equivalent ASTM E 119 30-minute fire exposure. Therefore, a fire

resistance capability of at least 30 minutes provides protection of the components required for achieving and maintaining safe shutdown. Therefore, the underlying purpose of the rule is satisfied and the application of the regulation in these particular circumstances is not necessary to achieve the underlying purpose of the rule.

7.0 CONCLUSION

The defense-in-depth objectives of the Fire Protection Program are to

1) Prevent fires from occurring;

2) Detect, control, and extinguish promptly those fires that do occur; and,

3) Provide protection from the effects of a fire for structures, systems, and components needed to achieve and maintain safe shutdown.

The fire hazards analysis of the fire zones containing the Hemyc ERFBS installations and the existing protection (after completion of modifications discussed in Section 5.0) of the electrical raceways show that these objectives are met. The first objective is supported by the fact that there are few significant ignition sources[1] in the areas, and transient combustibles are controlled. Supporting the second objective are the active fire detection and suppression features in each area. The third objective is supported by the Hemyc ERFBS configurations which provide protection from credible fire exposures, which have an expected duration less than that of the proposed 30 minute rating.

This request for revision of existing exemptions is warranted under the provisions of 10 CFR 50.12, in that it is authorized by law, does not present an undue risk to the public health and safety, and is consistent with the common defense and security. Further, it meets the requirement for a special circumstance in that it satisfies the underlying purpose of 10 CFR 50 Appendix R by providing an ERFBS that will provide protection for the duration of any postulated fire such that safe shutdown can be achieved and maintained.

[1] Ignition sources in the affected fire zones consist of limited transient combustibles (all zones), several equipment cabinets and (3kVA) 480/120V instrument power transformer BH8 (Fire Zone 73A), and a CCW pump motor (Fire Zone 1)

8.0 REFERENCES

8.1 NRC Letter and SER, S. A. Varga to J. C. Brons (NYPA); Indian Point 3 Nuclear Power Plant - Exemption From Certain Requirements of Section III.G and III.J of Appendix R to 10 CFR Part 50, January 7, 1987

8.2 NYPA Letter, J. C. Brons to S. A. Varga (NRC); Information to Support the Evaluation of IP3 to 10 CFR 50.48 and Appendix R to 10 CFR 50, September 19, 1985

8.3 NYPA Letter, J. C. Brons to S. A. Varga (NRC); Appendix R Fire Protection Program, August 16, 1984

8.4 NRC Letter and SER, S. A. Varga to J. C. Brons (NYPA); Exemptions From the Requirements of 10 CFR 50, Appendix R, for the Indian Point Nuclear Generating Plant, Unit No. 3 (IP-3), February 2, 1984

8.5 Hemyc (One-Hour) Electrical Raceway Fire Barrier Systems Performance Testing; Conduit and Junction Box Raceways (Omega Point Laboratories Fire Test Report, Project 14790-123263, dated April 11, 2005)

8.6 Hemyc (One-Hour) Electrical Raceway Fire Barrier Systems Performance Testing; Cable Tray, Cable Air Drop and Junction Box Raceways (Omega Point Laboratories Fire Test Report, Project 14790-123264, dated April 18, 2005)

8.7 IP3-ANAL-FP-02143, Indian Point 3 Fire Hazards Analysis, Revision 4

8.8 EN-DC-127, Control of Hot Work and Ignition Sources, Revision 2

8.9 ENN-DC-161, Transient Combustible Program, Revision 1

8.10 NUREG-1805, "Fire Dynamics Tools (FDTs) Quantitative Fire Hazard Analysis Methods for the U.S. NRC Fire Protection Inspection Program," December 2004.

8.11 Entergy Engineering Report IP-RPT-06-00062, Revision 0; "Comparison of IP3 Hemyc Electrical Raceway Fire Barrier System to NRC Hemyc Fire Test Results."

9.0 FIGURES

9.1 Hemyc ERFBS in Fire Zone 1

9.2 Hemyc ERFBS in Fire Zone 7A

9.3 Hemyc ERFBS in Fire Zone 60A

9.4 Hemyc ERFBS in Fire Zone 73A

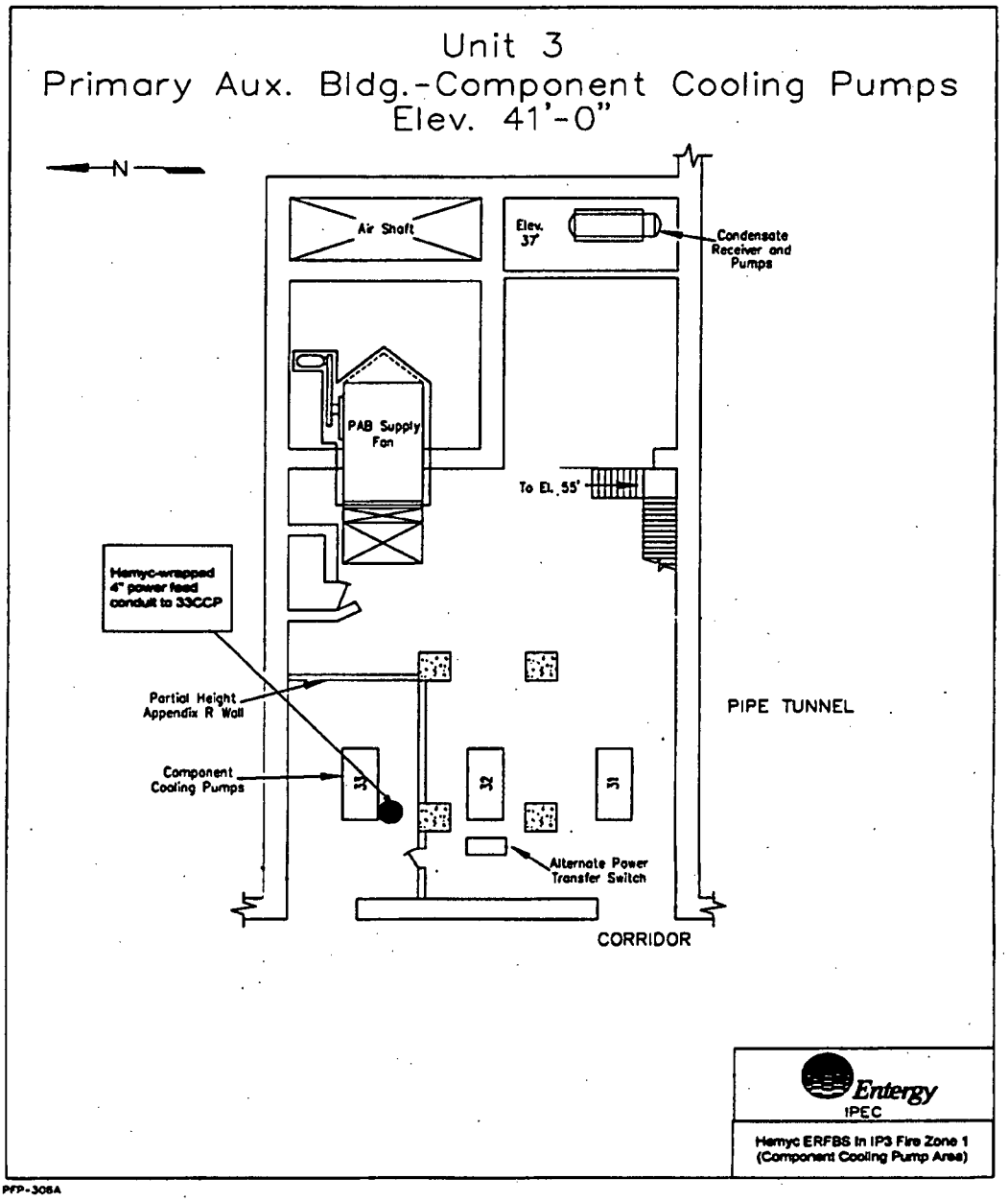

Figure 9.1: Hemyc ERFBS in Fire Zone 1

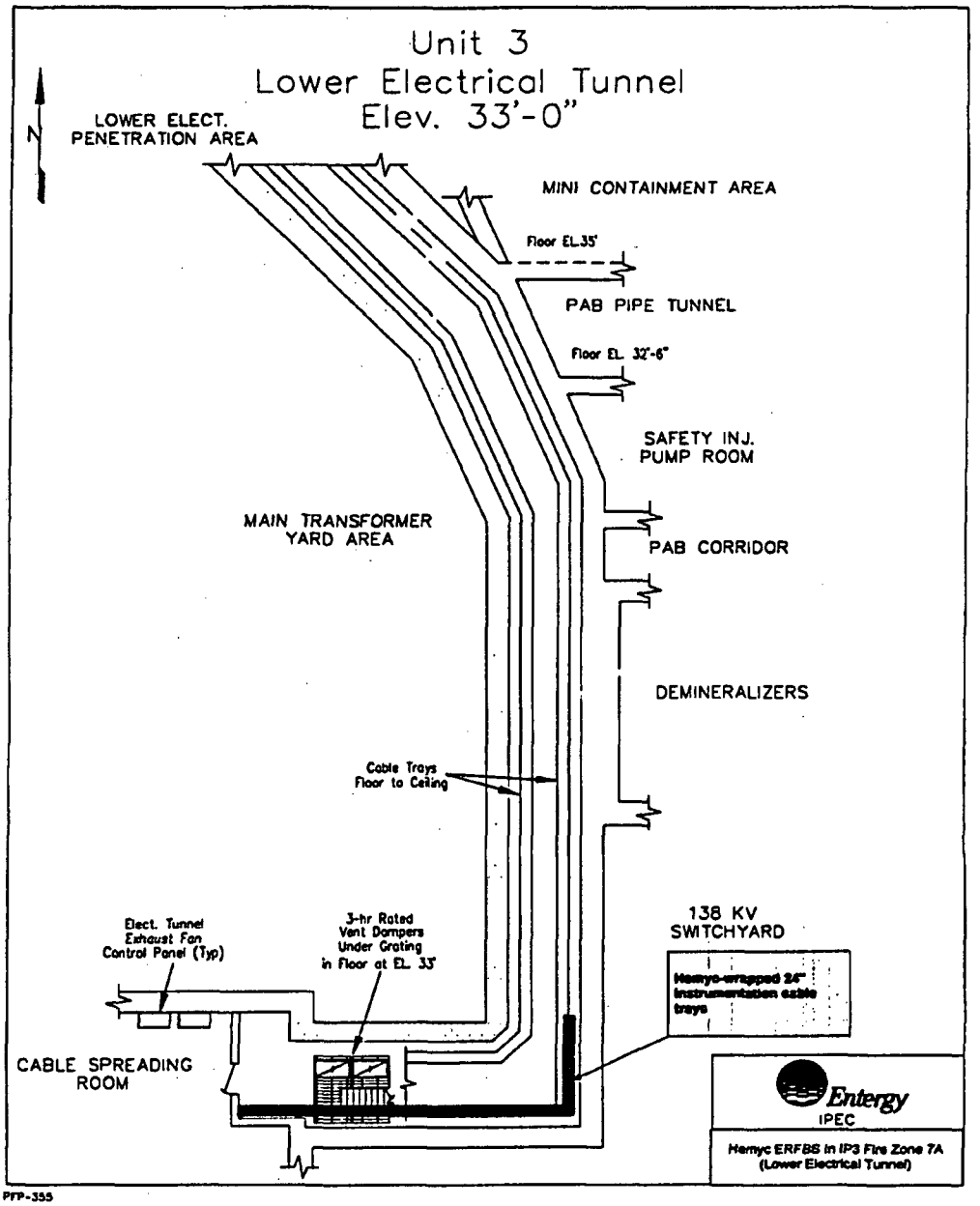

Figure 9.2: Hemyc ERFBS in Fire Zone 7A

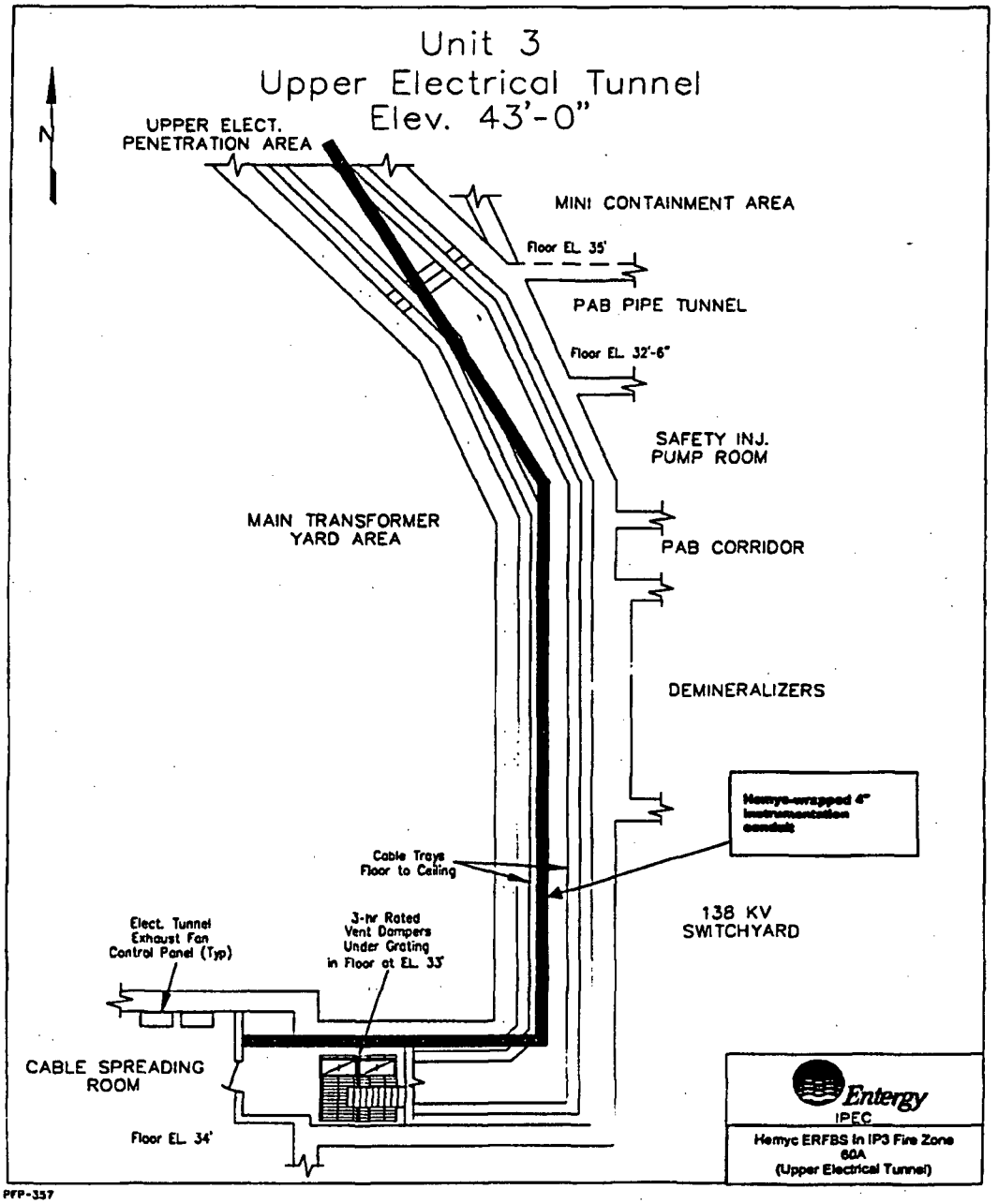

Figure 9.3: Hemyc ERFBS in Fire Zone 60A

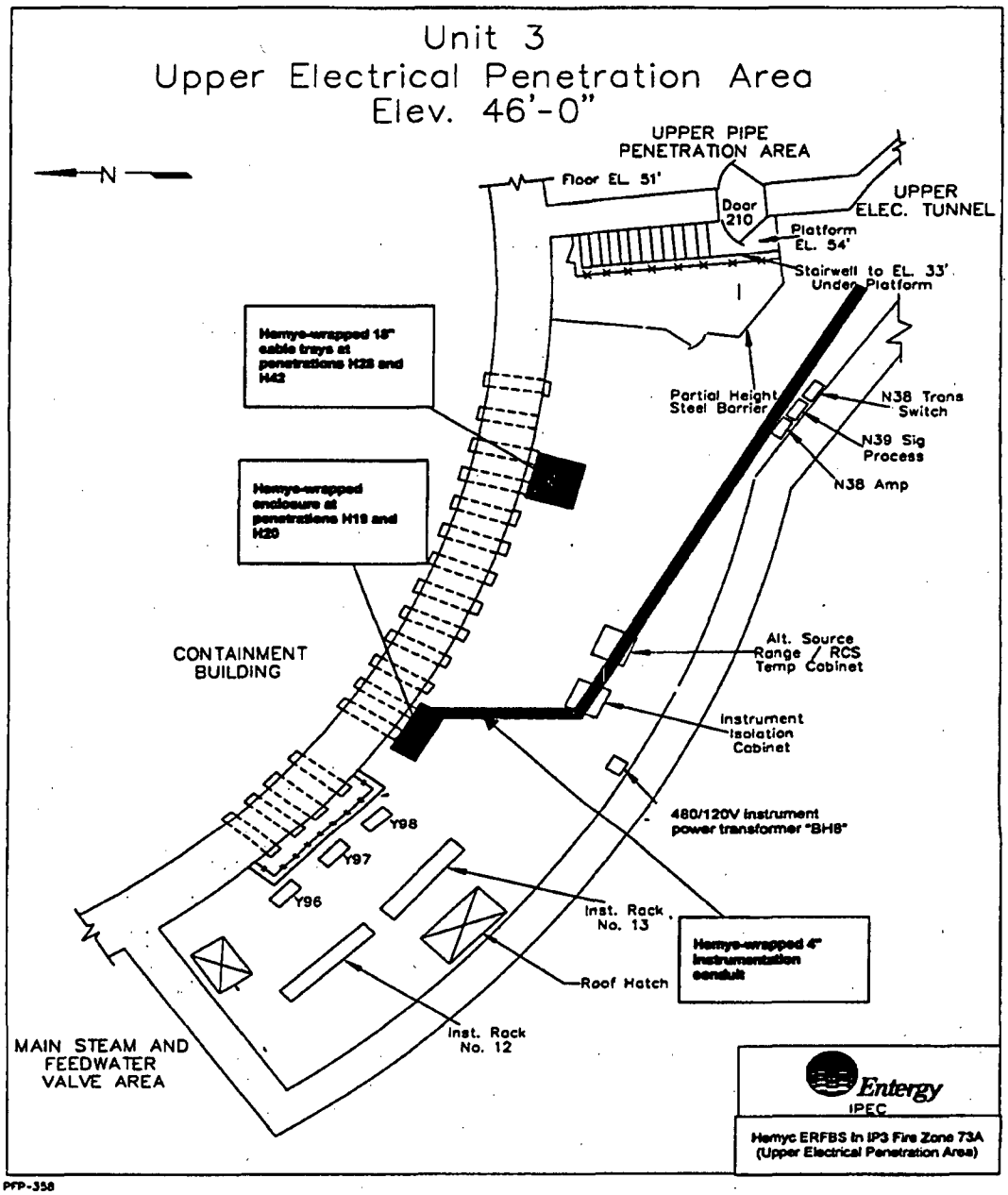

Figure 9.4: Hemyc ERFBS in Fire Zone 73A

Exhibit FP No. 6

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel 914 734 6700

Fred Dacimo
Site Vice President
Administration

August 16, 2007

Re: Indian Point Unit No. 3
Docket No. 50-286

NL-07-084

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

SUBJECT: **Supplement to the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2 for Indian Point Nuclear Generating Unit No. 3 (TAC No. MD2671)**

REFERENCES:

1. Entergy letter dated July 24, 2006, F.R. Dacimo to Document Control Desk, "Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2"

2. NRC Letter and SER dated January 7, 1987, S.A. Varga to J.C. Brons (NYPA), "Indian Point 3 Nuclear Power Plant – Exemption from Certain Requirements of Section III.G and III.J of Appendix R to 10 CFR Part 50"

3. NRC letter dated March 15, 2007, J.P. Boska to M.R. Kansler, "Indian Point Nuclear Generating Unit No. 3 - Request for Additional Information Regarding the Revision of Existing Exemptions from Title 10 of the Code of Federal Regulations Part 50, Appendix R Requirements (TAC No. MD2671)"

4. Entergy letter dated April 30, 2007, F.R. Dacimo to Document Control Desk, "Response to Request for Additional Information Regarding the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2 for Indian Point Nuclear Generating Unit No. 3"

5. Entergy letter dated May 23, 2007, F.R. Dacimo to Document Control Desk, "Supplemental Response to Request for Additional Information Regarding the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2 for Indian Point Nuclear Generating Unit No. 3 (TAC No. MD2671)"

A006
NRR

Dear Sir or Madam:

By letter dated July 24, 2006 (Reference 1), Entergy Nuclear Operations, Inc. submitted a "Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2." The letter requested revision of the January 7, 1987 NRC SER (Reference 2) to reflect that the installed Hemyc Electrical Raceway Fire Barrier System (ERFBS) configurations provide a 30-minute fire resistance rating, in lieu of the previously stated one-hour fire resistance rating. This applies to Hemyc ERFBS that is installed on conduit, cable tray, and a box-type enclosure in Fire Areas ETN-4 and PAB-2. The NRC staff requested additional information by letter dated March 15, 2007 (Reference 3) in order to complete its review of the request. Responses to questions 2 through 6 were provided by letter dated April 30, 2007 (Reference 4), and the response to question 1 was provided in a letter dated May 23, 2007 (Reference 5).

The purpose of this letter is to revise the request made in Reference 1 relative to the cable tray Hemyc ERFBS configurations, in light of new information obtained since the letter was submitted. Entergy herein requests revision of the January 7, 1987 SER to reflect that the installed Hemyc ERFBS configurations in Fire Area ETN-4 on the cable tray provide a 24-minute fire resistance rating, in lieu of the previously stated one-hour fire resistance rating in the January 7, 1987 NRC SER. The revised request for a 24-minute fire resistance rating for the cable tray Hemyc ERFBS configurations is in lieu of the 30-minute fire resistance rating requested in our July 24, 2006 letter. Attachment 1 contains supporting information for this revised request. We consider this conservatively interpreted fire resistance rating for the cable tray Hemyc ERFBS configurations to provide an adequate level of protection for the enclosed safe-shutdown cables in Fire Area ETN-4, given the limited amounts and types of hazards in the area and the active and passive fire protection features that are provided.

Commitments made in this letter are identified in Attachment 2. If you have any questions or require additional information, please contact Mr. R.W. Walpole, Manager, Licensing at (914) 734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 8/16/2007.

Sincerely,

For

Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachments:

1: Supplement to the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

2: Commitments made in Supplement to the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

cc: Mr. John P. Boska, Senior Project Manager, NRC NRR DORL

Mr. Samuel J. Collins, Regional Administrator, NRC Region 1

NRC Resident Inspector, IPEC

Mr. Peter R. Smith, President, NYSERDA

Mr. Paul Eddy, New York State Dept. of Public Service

ATTACHMENT 1 to NL-07-084

Supplement to the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

Supplement to the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

By letter dated July 24, 2006 (Reference 1), Entergy requested revision of the January 7, 1987 NRC SER (Reference 2) to reflect that the installed Hemyc Electrical Raceway Fire Barrier System (ERFBS) configurations in Fire Areas ETN-4 and PAB-2 provide a 30-minute fire resistance rating, in lieu of the previously stated one-hour fire resistance rating. This applies to Hemyc ERFBS that is installed on conduit, cable tray, and a box-type enclosure. Responses to a request for additional information (Reference 3) were provided by letters dated April 30, 2007 (Reference 4) and May 23, 2007 (Reference 5). In the referenced Entergy correspondence, information was provided to support a revision of the 1-hour fire resistance rating, establishing that a 30-minute fire resistance rating would provide adequate protection for the safe-shutdown cables, in light of the hazards and fire protection features of the areas. The information herein supplements and revises the request for revision of the January 7, 1987 SER for the installed cable tray Hemyc ERFBS configurations in Fire Area ETN-4 from a one-hour fire resistance rating to a 24-minute fire resistance rating.

Cable Tray Sections

As stated in Reference 1, the installed cable tray Hemyc ERFBS configurations consist of the following:

> Seven 18" cable tray sections, with a cable percent fill in these trays ranging from approximately 10% to 25%. Also wrapped are two 24" cable tray sections, each with a cable percent fill of approximately 50%. All cable trays are wrapped using 1-1/2" thick Hemyc blanket with a 2" air gap between the blanket and the protected raceway.

In preparing Reference 1 and as documented in Reference 6, the results from several test configurations from the NRC Hemyc fire test program conducted in 2005 were applied to those of comparable Indian Point 3 (IP3) installed Hemyc ERFBS configurations in the affected fire areas. For the cable tray configurations, Entergy referenced the fire test results (Reference 7) of cable tray Configurations 2B and 2D, noting that Configuration 2B provided thermal protection for the enclosed cables of at least 30 minutes, and Configuration 2D provided thermal protection for approximately 27 minutes before exceeding the temperature rise acceptance criteria. Recognizing that Configuration 2D failed to provide 30 minutes of thermal protection, and interpreting Hemyc joint separation as a contributing factor, it was proposed to install additional stainless steel over-banding on the installed cable tray Hemyc ERFBS configurations in the affected fire zones of Fire Area ETN-4 to minimize the potential for mechanical failure of the ERFBS under fire exposure conditions in the belief that this would enable the installed configurations to better resist a 30-minute exposure fire.

As of the date of the Entergy submittal (Reference 1), additional Hemyc fire testing by the industry had not yet been completed, and thus further meaningful comparative data was not available for consideration. By NRC letter dated March 15, 2007 (Reference 3), Entergy was requested to consider the results of other industry Hemyc fire testing to assess whether the results of this testing impacted any of the conclusions reached in Entergy's July 24, 2006 request.

In the response to Reference 3 provided by letter dated May 23, 2007 (Reference 5), the results for tested cable tray Hemyc ERFBS Configurations A-1, A-2, and A-3 from industry fire testing (documented in Reference 8), all constructed with zero percent fill and a 2" air gap, were used to evaluate comparable IP3 installed cable tray Hemyc configurations. Configuration A-2 consisted of multiple 24" cable trays, while Configurations A-1 and A-3 each consisted of a single 24" cable tray. Configurations A-2 and A-3 provided thermal protection for at least 30 minutes before exceeding the temperature rise acceptance criteria, but Configuration A-1 exceeded the temperature rise acceptance criteria at approximately 24 minutes into the exposure period. To compensate for the failure of Configuration A-1, which Entergy attributed to the apparent infiltration of hot gases due to joint separation, it was reiterated in Reference 5 that Entergy intended to install over-banding on the installed cable tray configurations to minimize the potential for joint separation in an effort to achieve a 30-minute fire resistance rating.

Subsequent to Entergy letter dated May 23, 2007 (Reference 5), discussions with the Staff were held and further review of the industry Hemyc fire test data in Reference 8 was performed. Despite the successful minimum 30-minute performance of Configurations A-2 and A-3, the postulated success of a third comparable Configuration (A-1) to perform for a minimum of 30 minutes via the use of over-banding cannot be definitively demonstrated. Moreover, the affected IP3 cable trays contain at least 10% cable fill versus the zero percent fill in the tested configurations, and although not qualifiable the heat sink afforded by the copper conductors can be expected to moderate the temperature inside the IP3 installed cable tray Hemyc ERFBS configurations. As a result, it has been determined that the more limiting performance of Configuration A-1 should be used as the basis for the installed cable tray Hemyc ERFBS configurations fire resistance rating. Therefore, for purposes of this request, Entergy considers the fire resistance capability of the installed cable tray Hemyc ERFBS configurations in Fire Area ETN-4 to be 24 minutes without the use of over-banding.

A comparison of the 24-minute fire resistance rating to the fire hazards in Fire Area ETN-4 demonstrates the adequacy of this rating. The subject cable trays provided with Hemyc ERFBS configurations are located in Fire Zones 7A, 60A, and 73A. These fire zones have computed combustible loading values as shown below, with electrical cable insulation in the cable trays being the dominant contributor in each zone.

Fire Zone	Total Combustible Load (BTU/ft^2)	Equivalent Fire Severity (Minutes)	Combustible Load Contributed by Cables (BTU/ft^2)	Incidental Combustible Loading, (BTU/ft^2)	Equivalent Fire Severity, Combustibles Other Than Cables (Minutes)
7A	78,716	59	78,316	400	< 1
60A	90,991	68	90,591	400	< 1
73A	127,239	95	126,839	400	< 1

The electrical cables installed in cable trays in Fire Area ETN-4, inclusive of the fire zones listed above, are of flame-retardant construction, and will not constitute a significant component of the fuel source for credible fire scenarios in this area. In an SER dated February 2, 1984 (Reference 9), the NRC Staff stated that (given the flame-retardant cable construction and the results of testing as described in a NYPA letter dated November 22, 1982 (Reference 10)), "... a postulated fire commensurate with the transient fire hazard [in Fire Area ETN-4] would not cause propagation along the cables to a significant degree." This was the basis for the granting of an exemption in that SER from the requirement to consider electrical cable in the Electrical Tunnels as an intervening combustible. Therefore, the electrical cables in the fully-suppressed cable trays in Fire Area ETN-4 are considered to be a negligible contributor to any credible fire scenario in that area.

The fuel loading contribution from the credible fire hazards in the area, exclusive of the cable insulation and inclusive of transient and incidental combustibles, represents an insignificant fire challenge to systems, structures, and components in Fire Area ETN-4. For the range of credible fire scenarios, a 24-minute fire resistance rating provided by the installed cable tray Hemyc ERFBS configurations will provide adequate protection, with margin, of the credited safe-shutdown capability.

Conclusions

In light of the limited amounts and types of hazards in Fire Area ETN-4, the full-area coverage fire detection system, the fixed automatic cable tray fire suppression system, and available manual suppression features, the conservative fire resistance rating of 24 minutes of the IP3 installed cable tray Hemyc ERFBS configurations is considered to provide adequate protection, with margin, for the enclosed safe-shutdown cables in Fire Area ETN-4.

Therefore, by this letter, Entergy Nuclear Operations, Inc.:

1. Requests revision of the January 7, 1987 SER to reflect that the installed Hemyc ERFBS configurations in Fire Area ETN-4 on the cable tray provide a 24-minute fire resistance rating, in lieu of the previously stated one-hour fire resistance rating in the January 7, 1987 NRC SER. The revised request for a 24-minute fire resistance

rating for the cable tray Hemyc ERFBS configurations is in lieu of the 30-minute fire resistance rating requested in our July 24, 2006 letter.

2. Modifies the Commitment (Number 3) originally presented in Attachment 2 to Reference 11 and subsequently modified as presented in Attachment 2 to Reference 5, to clarify the commitment on installation of stainless steel over-banding. Given that a definitive solution for the failure of test Configuration A-1 to meet temperature rise criteria has not been demonstrated, the value of installing over-banding on the installed cable tray Hemyc ERFBS configurations is indeterminate. As such, Entergy will not install such over-banding on IP3 installed cable tray Hemyc ERFBS configurations as discussed in References 1 and 5. This revised commitment is contained in Attachment 2 to this letter.

References

1. Entergy letter dated July 24, 2006, F.R. Dacimo to Document Control Desk, "Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2"

2. NRC Letter and SER dated January 7, 1987, S.A. Varga to J.C. Brons (NYPA), "Indian Point 3 Nuclear Power Plant – Exemption from Certain Requirements of Section III.G and III.J of Appendix R to 10 CFR Part 50"

3. NRC letter dated March 15, 2007, J.P. Boska to M.R. Kansler, "Indian Point Nuclear Generating Unit No. 3 - Request for Additional Information Regarding the Revision of Existing Exemptions from Title 10 of the Code of Federal Regulations Part 50, Appendix R Requirements (TAC No. MD2671)"

4. Entergy letter dated April 30, 2007, F.R. Dacimo to Document Control Desk, "Response to Request for Additional Information Regarding the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2 for Indian Point Nuclear Generating Unit No. 3"

5. Entergy letter dated May 23, 2007, F.R. Dacimo to Document Control Desk, "Supplemental Response to Request for Additional Information Regarding the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2 for Indian Point Nuclear Generating Unit No. 3 (TAC No. MD2671)"

6. Entergy Engineering Report IP-RPT-06-00062, Revision 0; "Comparison of IP3 Hemyc Electrical Raceway Fire Barrier System to NRC Hemyc Fire Test Results"

7. Hemyc (One-Hour) Electrical Raceway Fire Barrier Systems Performance Testing; Cable Tray, Cable Air Drop, and Junction Box Raceways (Omega Point Laboratories Fire Test Report, Project 14790-123264, dated April 18, 2005)

8. Report of Testing Hemyc 1-Hour ERFBS for Compliance with the Applicable Requirements of the Following Criteria: Generic Letter 86-10, Supplement 1 (Intertek Testing Services NA Inc. Fire Test Report 3106846, dated January 16, 2007; Revised February 5, 2007)

9. NRC letter dated February 2, 1984, D.G. Eisenhut to J.P. Bayne, "Exemptions from the Requirements of 10 CFR 50, Appendix R, for the Indian Point Nuclear Generating Plant, Unit No. 3 (IP-3)"

10. NYPA letter dated November 22, 1982, J.P. Bayne to H.R. Denton, "Indian Point 3 Nuclear Power Plant, Docket No. 50-286, Appendix R"

11. Entergy letter dated June 8, 2006, F.R. Dacimo to Document Control Desk, "Response to Generic Letter 2006-03, Potentially Nonconforming Hemyc and MT Fire Barrier Configurations"

ATTACHMENT 2 to NL-07-084

Commitments made in Supplement to the Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNIT 3
DOCKET NO. 50-286

This table identifies actions discussed in this letter for which Entergy commits to perform. Any other actions discussed in this submittal are described for the NRC's information and are not commitments.

Number	Commitment	Type	Scheduled Completion Date
3	Complete modification (including supporting engineering evaluation) to install additional protection of the electrical raceway supports and protection of certain metallic penetrating items associated with the existing Hemyc ERFBS located outside containment, and to install stainless steel over-banding on the box-type configuration (as described) located outside containment. [This is a further clarification of commitment 3 (licensee reference number COM-07-00034) which was initially made in Entergy Letter NL-06-060 dated June 8, 2006, and which was clarified in Entergy Letter NL-07-061 dated May 23, 2007]	One-Time Action	12/01/2008

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel 914 734 6700

Fred Dacimo
Site Vice President
Administration

July 24, 2006

Re: Indian Point Unit No. 3
Docket No. 50-286
NL-06-078

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

SUBJECT: Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

References:

1) NRC Information Notice 2005-07, "Results of HEMYC Electrical Raceway Fire Barrier System Full Scale Fire Testing," April 1, 2005

2) NYPA Letter, J. C. Brons to S. A. Varga (NRC), "Appendix R Fire Protection Program," August 16, 1984

3) NYPA Letter, J. C. Brons to S. A. Varga (NRC), "Information to Support the Evaluation of IP3 to 10 CFR 50.48 and Appendix R to 10 CFR 50," September 19, 1985

4) NRC Letter and SER, S. A. Varga to J. C. Brons (NYPA), "Indian Point 3 Nuclear Power Plant - Exemption From Certain Requirements of Section III.G and III.J of Appendix R to 10 CFR Part 50," January 7, 1987

5) IPEC Letter NL-06-060, F. Dacimo to Document Control Desk, "Response to Generic Letter 2006-03 (Potentially Nonconforming Hemyc and MT Fire Barrier Configurations)," June 8, 2006

Dear Sir or Madam:

NRC Information Notice (IN) 2005-07 (Reference 1) notified licensees of potential performance concerns associated with the one-hour rated Hemyc electrical raceway fire barrier system (ERFBS), indicating that the system may be incapable of fulfilling the stated one-hour fire resistance rating when tested in accordance with Generic Letter 86-10, Supplement 1 criteria. Indian Point Unit No. 3 (IP3) utilizes the one-hour rated Hemyc

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ERFBS that is the subject of IN 2005-07 in two areas of the plant. In a Safety Evaluation Report (SER) dated January 7, 1987 (Reference 4) , the Staff granted a number of exemptions from specific requirements of 10 CFR 50, Appendix R, which included these two plant areas. Entergy has reviewed the Hemyc fire test results provided by the NRC in IN 2005-07 and has determined that it is necessary to revise the fire resistance rating of the Hemyc ERFBS configurations credited in two of the exemptions. The two affected exemptions are those applicable to Fire Area PAB-2 in the Primary Auxiliary Building, and Fire Area ETN-4 in the Electrical Tunnels and Electrical Penetration Areas.

In accordance with 10 CFR 50.12, the purpose of this letter is to request revision of the January 7, 1987 SER to reflect that the installed Hemyc ERFBS configurations provide a 30-minute fire resistance rating, in lieu of the previously stated one-hour fire resistance rating. The requests for the exemptions granted by the January 7, 1987 SER were docketed in NYPA Letters dated August 16, 1984 (Reference 2) and September 19, 1985 (Reference 3). Based on a review of these letters and of the NRC test results, it is Entergy's position that a Hemyc ERFBS fire resistance rating of 30 minutes will provide sufficient protection for the affected raceways, with adequate margin, to continue to meet the intent of the original requests for exemption and the conclusions presented in the January 7, 1987 SER. This evaluation is summarized in Attachment 1.

As documented in Attachment 1, it is Entergy's conclusion that the revised fire resistance rating of the Hemyc ERFBS does not reflect a reduction in overall fire safety, and presents no added challenge to the credited post-fire safe-shutdown capability. The remainder of the credited fire protection features, the fire hazards and ignition sources, fire brigade and operator response to fire events, and the credited post-fire safe-shutdown capability remain materially unchanged from the configuration as originally described in the NYPA letters and as credited in the January 7, 1987 SER.

Entergy has reviewed the as-built configurations of the Hemyc ERFBS installed at IP3 against the results of the NRC Hemyc fire test program as referenced by IN 2005-07. This review has determined that the installed ERFBS can be expected to afford a thermal protection rating of at least 30 minutes, contingent upon the installation of a modification to augment raceway support protection and to install over-banding of certain enclosures. A commitment to install these modifications is contained in our response to Generic Letter 2006-03 (Reference 5). The conclusions from the engineering evaluation are also summarized in Attachment 1.

There are no new commitments contained in this letter. If you have any questions or require additional information, please contact Mr. Patric W. Conroy at 914-734-6668.

Sincerely,

for Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachment 1: Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

cc: Mr. Samuel J. Collins, Regional Administrator, NRC Region I
Mr. John P. Boska, Senior Project Manager, NRC NRR DORL
NRC Resident Inspectors Office, Indian Point Energy Center
Mr. Paul Eddy, New York State Department of Public Service
Mr. Peter R. Smith, NYSERDA

ATTACHMENT 1 to NL-06-078

Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

Entergy Nuclear Operations, Inc.
Indian Point Nuclear Generating Unit No. 3
Docket No. 50-286

Request for Revision of Existing Exemptions from 10 CFR 50, Appendix R: One-Hour Hemyc Electrical Raceway Fire Barrier System, Fire Areas ETN-4 and PAB-2

1.0 INTRODUCTION

The Indian Point Unit No. 3 (IP3) electrical raceways provided with Hemyc ERFBS protection consist of several conduits, cable trays, and a box-type enclosure. The locations of the Hemyc ERFBS installations are illustrated by Figures 1 through 4.

To support the request for revision to the two exemptions applicable to Fire Areas ETN-4 (Electrical Tunnels and Electrical Penetration Areas) and PAB-2 (Component Cooling Pump Area) contained in the January 7, 1987 SER (Reference 8.1), this attachment:

- Discusses the licensing basis for the one-hour Hemyc electrical raceway fire barrier system (ERFBS) (Section 2.0);
- Discusses the fire hazards, combustible controls, and fire protection features of the areas (Section 3.0);
- Evaluates the acceptability of a 30-minute rating considering the current fire hazards and fire protection features in the areas (Section 4.0);
- Presents a summary description of the installed one-hour Hemyc ERFBS configurations, and of the evaluation of the results of the NRC Hemyc fire test program (Reference 8.11) (Section 5.0).

As documented in Reference 8.11, the NRC Hemyc test specimens provided acceptable thermal performance for a period of at least 30 minutes, or the results provided insight into the observed failure mechanisms. Further, each of the installed IP3 Hemyc configurations is bounded by one or more of the NRC test specimens, or is subject to a planned modification based on the insights learned from the NRC test program. As determined in Reference 8.11, the Hemyc ERFBS at IP3 can be expected to provide a fire resistance rating of a minimum of 30 minutes, consistent with ASTM E 119 temperature rise acceptance criteria. A fire resistance rating of 30 minutes will provide adequate protection for the affected IP3 safe-shutdown raceways, in consideration of the additional mitigating factors of low fire loading and active and passive fire protection features installed in each of the two affected plant areas.

2.0 EXISTING LICENSING BASIS FOR ONE-HOUR ERFBS IN AFFECTED PLANT AREAS

2.1 Electrical Tunnels and Penetration Areas: Fire Area ETN-4: Upper and Lower Electrical Tunnels (Fire Zones 7A and 60A, respectively) and Upper Penetration Area (Fire Zone 73A)

By SER dated February 2, 1984 (Reference 8.4), the Staff approved an exemption from the Appendix R Section III.G separation requirements, to the extent that redundant safe-shutdown systems are not separated by more than 20 feet free of intervening combustibles or fire hazards, and that redundant safe-shutdown systems are not separated by a one-hour rated fire barrier in an area which is protected by automatic fire detection and suppression systems. The bases for this exemption included the existing separation between redundant safe-shutdown trains, minimal fire hazards, flame-retardant characteristics of cable insulation, and the installed active and passive fire protection features.

Following a comprehensive reassessment of the IP3 Appendix R compliance basis, by letters dated August 16, 1984 and September 19, 1985 (References 8.3 and 8.2, respectively), NYPA informed the NRC of the need for additional separation measures to be installed in Fire Area ETN-4. These measures included the installation of one-hour rated fire wrap on several safe-shutdown raceways. By SER dated January 7, 1987 (Reference 8.1), the Staff acknowledged this clarification and the addition of one-hour rated fire wrap, and confirmed the continued validity of the exemption granted by the February 2, 1984 SER (Reference 8.4).

2.2 Primary Auxiliary Building, Fire Area PAB-2: Fire Zone 1, 41' Elevation CCW Pump Area

In the SER dated January 7, 1987 (Reference 8.1), the Staff approved an exemption from the Section III.G separation requirements for this fire zone, to the extent that an automatic suppression system has not been provided, and redundant safe-shutdown systems are not separated by more than 20 feet free of intervening combustibles. The bases for this exemption included the existing separation between redundant safe-shutdown trains, low fire loading, a fire detection system, manual hose stations and portable extinguishers, a partial height noncombustible barrier designed to protect the CCW pump against radiant heat from a fire, and a one-hour fire rated cable wrap around the normal power feed conduit to the 33 CCW pump.

3.0 FIRE HAZARDS, COMBUSTIBLE CONTROLS, AND FIRE PROTECTION FEATURES IN FIRE AREAS ETN-4 AND PAB-2

3.1 Evaluation of Hazards/Ignition Sources and Combustible Controls

The fire hazards and ignition sources in Fire Areas ETN-4 and PAB-2 remain materially unchanged from the characteristics of these areas as described in the SERs dated February 2, 1984 (Reference 8.4) and January 7, 1987 (Reference 8.1), and the NYPA correspondence referenced therein, as applicable to the specific fire zone.

Transient combustible and hot work controls have been enhanced since the transition from NYPA to Entergy operation of IP3, with the issuance of procedures EN-DC-127, "Control of Hot Work and Ignition Sources" (Reference 8.8) and ENN-DC-161, "Transient Combustible Program" (Reference 8.9). Notably, per Transient Combustible Program procedure ENN-DC-161, Fire Areas ETN-4 and PAB-2 are designated as "Level 2" combustible control areas, which constrains transient combustibles to moderate quantities. Any planned introduction of more than the allowable quantities of combustibles into these areas requires a prior review by Fire Protection Engineering, which will include the definition of additional protective/compensatory measures as determined to be applicable. In addition, per procedure EN-DC-127, any planned hot work in IP3 Fire Areas ETN-4 or PAB-2 requires the prior review and approval of Fire Protection Engineering. This constraint provides assurance that hazards and potential effects consistently receive proper prior evaluation, and that compensatory measures, as applicable, are adequately defined in advance of the hot work activity.

The administrative controls imposed by ENN-DC-161 and the structured Fire Protection Engineering review of planned hot work activities per EN-DC-127 provide additional assurance that the potential for, and potential effects of, significant floor-based transient combustible fires is sharply limited.

3.2 Active Protection: Fire Detection and Suppression Features

The installed fire detection systems and automatic and manual fire suppression features in the affected zones of Fire Areas ETN-4 and PAB-2 remain functionally unchanged from those described in SERs dated February 2, 1984 (Reference 8.4) and January 7, 1987 (Reference 8.1), and the NYPA correspondence referenced therein, as applicable. Preaction automatic water spray suppression is provided in ETN-4 for protection of cable trays; manual suppression capabilities are provided in both Fire Areas ETN-4 and PAB-2, in the form of accessible fire hose stations and portable fire extinguishers.

3.3 Passive Fire Protection Features

The installed passive fire protection features (fire barriers and penetration seal systems) in Fire Areas ETN-4 and PAB-2 remain functionally unchanged from those described in SERs dated February 2, 1984 (Reference 8.4) and January 7, 1987 (Reference 8.1), and the NYPA correspondence referenced therein, as applicable.

3.4 Transient Combustible Control and FP Equipment Operating History

A review of IP3 condition reports for the period beginning with Entergy ownership through the present indicated that no significant fire protection related deficiencies applicable to Fire Zones 1, 7A, 60A, or 73A were identified during this time period. Topics searched included fire barriers, ERFBS, fire suppression, fire detection, and housekeeping/combustible loading. Hence, there is reasonable assurance that the design and operational controls (as described above) in place since the transition to Entergy operation of IP3 have maintained the fire protection defense-in-depth measures consistent with the IP3 fire protection licensing basis.

4.0 ADEQUACY OF A 30-MINUTE ERFBS TO PROTECT SAFE-SHUTDOWN CABLES

4.1 Fire Area ETN-4, Fire Zones 7A, 60A, and 73A

As described in the SER dated February 2, 1984 (Reference 8.4), the fire hazards in the affected zones of this area are small. As given by Reference 8.7, the calculated fire severity in Fire Area ETN-4 is less than 60 minutes, of which less than one minute of fire severity is attributable to the expected transient fire loading. The balance of the combustible inventory is predominantly asbestos-jacketed, flame-retardant electrical cable insulation. The flame-retardant characteristics of the principal combustible ensure that fire will not propagate along the cables to any significant degree, thereby limiting the rate of development and damage incurred by credible fires. As the credible fire scenarios involve floor-based transient combustibles, the impact of such a fire, at any location within the area, is expected to be slight, and insufficient to involve substantial quantities of the predominant fixed combustibles (the flame-retardant cables in trays). In addition, the fire detection, automatic cable tray fire suppression system, and manual fire suppression features provide further assurance that fire damage will be limited in scope and severity. Therefore, based on the current Fire Hazards Analysis, an ERFBS with a 30-minute fire resistance rating is adequate to protect the safe-shutdown cables in this area.

Based on a review of the fire zones in this area using the guidance and tools of NUREG-1805 (Reference 8.10), it was found that the credible fire challenge would be less severe than that imposed by an ASTM E 119 fire exposure. Further, with the installed smoke detection system and the preaction water spray system for the cable trays in the area, the credible fire challenge in the affected zones of Fire Area ETN-4 can be expected to result in a temperature profile that is substantially less severe than that of the ASTM E 119 time-temperature curve. Therefore, based on the insights using NUREG-1805 guidance and tools, the expected fire effects in this Fire Area will not challenge a Hemyc ERFBS installation that has a fire resistance rating of 30 minutes.

4.2 Fire Area PAB-2, Fire Zone 1

As described in the SER dated January 7, 1987 (Reference 8.1), the fire load in this area is low. As given by Reference 8.7, the calculated fire severity in Fire Area PAB-2, Fire Zone 1 is less than 10 minutes. The small quantity of combustible materials (e.g., CCW pump lubricating oil or transient materials) would be expected to result in a credible fire which is localized, with a low aggregate heat release, and no challenge to redundant safe-shutdown cables or components caused by radiant or convective energy. The installed fire detection system would ensure timely detection, enable prompt manual suppression of the fire, and provide assurance that any fire damage will be limited in scope and severity. Therefore, the credible fire challenge can be expected to result in a temperature profile less severe than that of the ASTM E 119 time-temperature curve.

Hence, an ERFBS capable of providing at least 30 minutes of protection for the enclosed cables when tested in accordance with ASTM E 119 will provide adequate protection for the safe-shutdown cables in this area, given the hazards in the area and the active fire protection features.

5.0 EVALUATION OF IP3-SPECIFIC HEMYC ERFBS VERSUS NRC-TESTED CONFIGURATIONS

The installed IP3 Hemyc ERFBS is summarized as follows:

- Two 4" rigid steel conduits, each with a cable percent fill of approximately 30%. The two 4" rigid steel conduits are protected with direct-attached 2" thick Hemyc blanket wrap.

- Seven 18" cable tray sections, with a cable percent fill in these trays ranging from approximately 10% to 25%. Also wrapped are two 24" cable tray sections, each with a cable percent fill of approximately 50%. All cable trays

are wrapped using 1-1/2" thick Hemyc blanket with a 2" air gap between the blanket and the protected raceway.

- Box-type enclosure at containment electrical penetrations H19/H20, consisting of 2" thick Hemyc blanket directly attached to the enclosure.

The IP3 Hemyc ERFBS configurations have been compared to the size, orientation, materials, methods of construction, and thermal performance of the test specimens of References 8.5 and 8.6 in an engineering evaluation (Reference 8.11). The detailed thermal performance results of the NRC Hemyc fire tests indicated that several of the tested configurations provided at least 30 minutes of protection for the enclosed safe-shutdown cables, or provided insights into the failure mechanisms that occurred during testing. The engineering evaluation compares the details of these tested configurations with the details of the IP3 Hemyc ERFBS configurations. This evaluation establishes that the IP3 Hemyc ERFBS configurations are sufficiently comparable to the NRC-tested configurations, with minor enhancements to several IP3 configurations, which include the need to augment the ERFBS on raceway supports and to install additional over-banding on certain enclosures. Pending implementation of those modifications to the affected configurations, all of the IP3 Hemyc ERFBS configurations can be expected to provide a fire resistance capability of at least 30 minutes for the enclosed safe-shutdown cables.

6.0 REGULATORY ANALYSIS

10 CFR 50.12(a) states that the Commission may grant exemptions from the requirements of the regulations contained in 10 CFR 50 which are:

(1) Authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security; and,

(2) If special circumstances are present.

This request for revision of existing exemptions meets the criteria set forth in 10 CFR 50.12, as discussed herein.

6.1 The requested exemption is authorized by law

10 CFR 50.12(a) authorizes the NRC to grant exemptions from its regulations, and no law is known that precludes the NRC from granting the requested revision to the existing exemptions.

6.2 The requested exemption does not present an undue risk to the public health and safety

The Hemyc ERFBS configurations installed in IP3 Fire Areas ETN-4 and PAB-2 will provide a fire resistance capability of at least 30 minutes, as discussed in Section 5.0. The minimal fire hazards and ignition sources, combined with the nature of the fire hazards in the areas, the active and passive fire protection features, and the controls on transient combustibles and ignition sources, as discussed in Section 3.0, provide assurance that the credible fire challenge to the IP3 Hemyc ERFBS will be substantially less than that of an equivalent ASTM E 119 30-minute fire exposure. Therefore, as discussed in Section 4.0, the installed ERFBS can be expected to provide adequate protection for the affected safe-shutdown raceways and enclosed cables.

Therefore, given the existing level of fire protection defense in depth, combined with the minimal fire challenge presented by the credible fire scenarios in these areas, and the favorable FP equipment operating history, the change in credited ERFBS fire resistance rating from one hour to 30 minutes will not degrade the effectiveness of the IP3 fire protection program, nor will it challenge the credited post-fire safe-shutdown capability. Based on the determination that safe shutdown in the event of a fire can be achieved and maintained with less than a one-hour fire resistance rating, the requested revision to the existing exemptions does not present an undue risk to the public health and safety.

6.3 The requested exemption is consistent with the common defense and security

The requested revision to the existing exemptions is not directly related to and should not adversely impact the common defense and security.

6.4 Special circumstances are present – underlying purpose of the rule

10 CFR 50.12(a) requires that special circumstance be present in order for the Commission to consider granting an exemption. Per 10 CFR 50.12(a)(2)(ii), one special circumstance is that application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule.

The underlying purpose of 10 CFR 50, Appendix R, Section III.G is to provide reasonable assurance that at least one means of achieving and maintaining safe shutdown conditions will remain available during and after any postulated fire. For the areas containing the Hemyc ERFBS installations, the credible fire challenge to the IP3 Hemyc ERFBS due to any postulated fire will be substantially less than that of an equivalent ASTM E 119 30-minute fire exposure. Therefore, a fire

resistance capability of at least 30 minutes provides protection of the components required for achieving and maintaining safe shutdown. Therefore, the underlying purpose of the rule is satisfied and the application of the regulation in these particular circumstances is not necessary to achieve the underlying purpose of the rule.

7.0 CONCLUSION

The defense-in-depth objectives of the Fire Protection Program are to

1) Prevent fires from occurring;

2) Detect, control, and extinguish promptly those fires that do occur; and,

3) Provide protection from the effects of a fire for structures, systems, and components needed to achieve and maintain safe shutdown.

The fire hazards analysis of the fire zones containing the Hemyc ERFBS installations and the existing protection (after completion of modifications discussed in Section 5.0) of the electrical raceways show that these objectives are met. The first objective is supported by the fact that there are few significant ignition sources[1] in the areas, and transient combustibles are controlled. Supporting the second objective are the active fire detection and suppression features in each area. The third objective is supported by the Hemyc ERFBS configurations which provide protection from credible fire exposures, which have an expected duration less than that of the proposed 30 minute rating.

This request for revision of existing exemptions is warranted under the provisions of 10 CFR 50.12, in that it is authorized by law, does not present an undue risk to the public health and safety, and is consistent with the common defense and security. Further, it meets the requirement for a special circumstance in that it satisfies the underlying purpose of 10 CFR 50 Appendix R by providing an ERFBS that will provide protection for the duration of any postulated fire such that safe shutdown can be achieved and maintained.

[1] Ignition sources in the affected fire zones consist of limited transient combustibles (all zones), several equipment cabinets and (3kVA) 480/120V instrument power transformer BH8 (Fire Zone 73A), and a CCW pump motor (Fire Zone 1)

8.0 REFERENCES

8.1 NRC Letter and SER, S. A. Varga to J. C. Brons (NYPA); Indian Point 3 Nuclear Power Plant - Exemption From Certain Requirements of Section III.G and III.J of Appendix R to 10 CFR Part 50, January 7, 1987

8.2 NYPA Letter, J. C. Brons to S. A. Varga (NRC); Information to Support the Evaluation of IP3 to 10 CFR 50.48 and Appendix R to 10 CFR 50, September 19, 1985

8.3 NYPA Letter, J. C. Brons to S. A. Varga (NRC); Appendix R Fire Protection Program, August 16, 1984

8.4 NRC Letter and SER, S. A. Varga to J. C. Brons (NYPA); Exemptions From the Requirements of 10 CFR 50, Appendix R, for the Indian Point Nuclear Generating Plant, Unit No. 3 (IP-3), February 2, 1984

8.5 Hemyc (One-Hour) Electrical Raceway Fire Barrier Systems Performance Testing; Conduit and Junction Box Raceways (Omega Point Laboratories Fire Test Report, Project 14790-123263, dated April 11, 2005)

8.6 Hemyc (One-Hour) Electrical Raceway Fire Barrier Systems Performance Testing; Cable Tray, Cable Air Drop and Junction Box Raceways (Omega Point Laboratories Fire Test Report, Project 14790-123264, dated April 18, 2005)

8.7 IP3-ANAL-FP-02143, Indian Point 3 Fire Hazards Analysis, Revision 4

8.8 EN-DC-127, Control of Hot Work and Ignition Sources, Revision 2

8.9 ENN-DC-161, Transient Combustible Program, Revision 1

8.10 NUREG-1805, "Fire Dynamics Tools (FDTs) Quantitative Fire Hazard Analysis Methods for the U.S. NRC Fire Protection Inspection Program," December 2004.

8.11 Entergy Engineering Report IP-RPT-06-00062, Revision 0; "Comparison of IP3 Hemyc Electrical Raceway Fire Barrier System to NRC Hemyc Fire Test Results."

9.0 FIGURES

9.1 Hemyc ERFBS in Fire Zone 1

9.2 Hemyc ERFBS in Fire Zone 7A

9.3 Hemyc ERFBS in Fire Zone 60A

9.4 Hemyc ERFBS in Fire Zone 73A

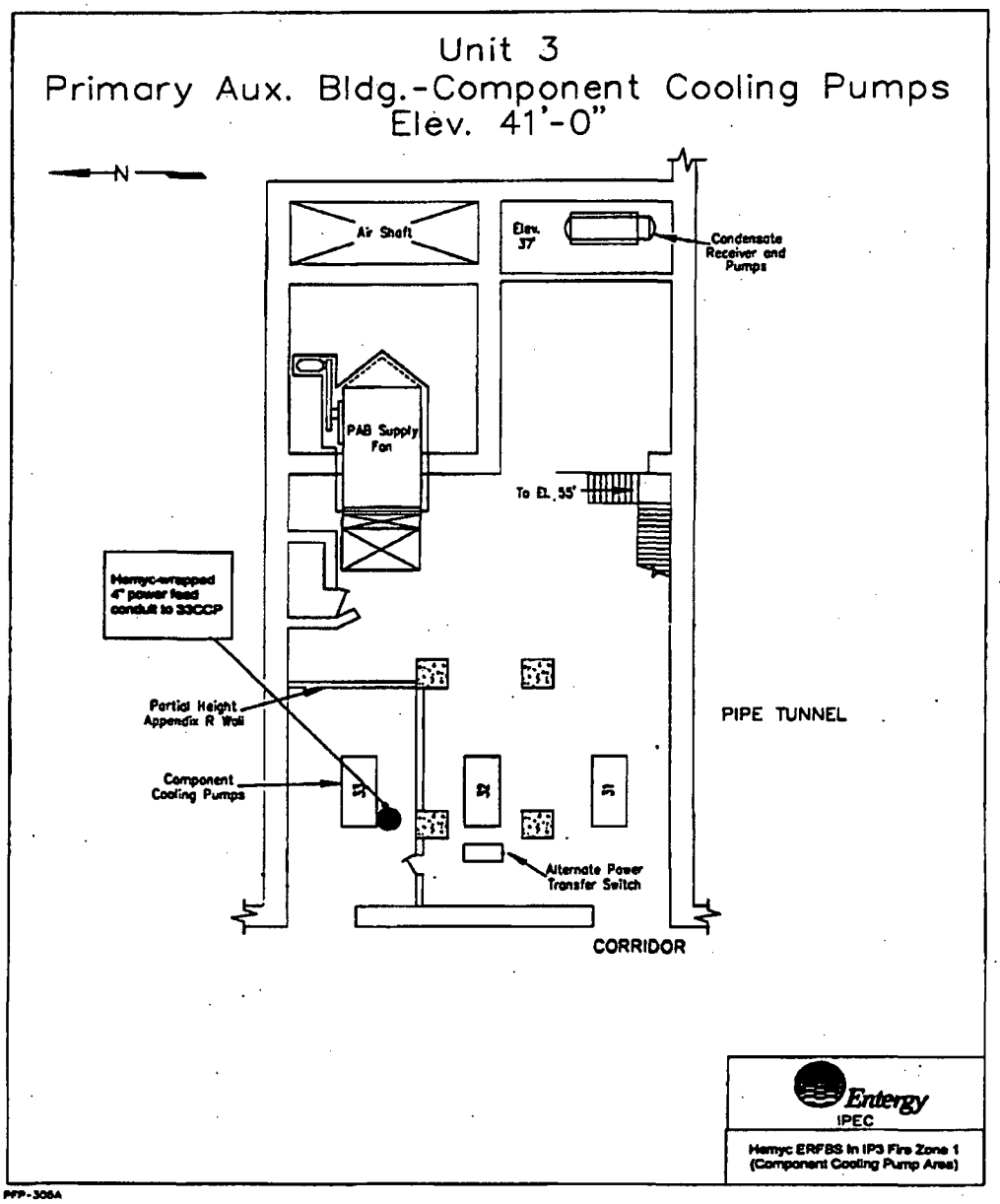

Figure 9.1: Hemyc ERFBS in Fire Zone 1

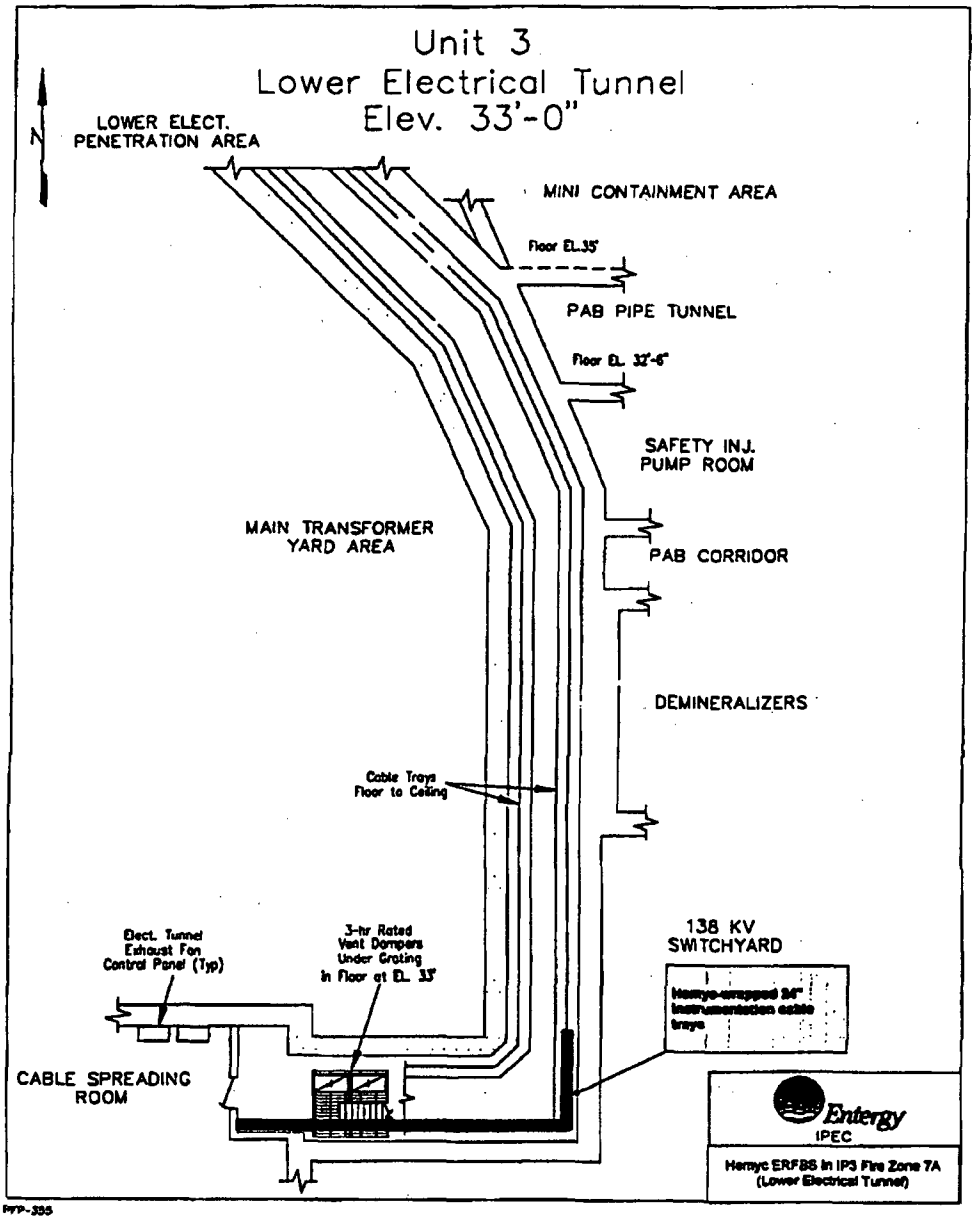

Figure 9.2: Hemyc ERFBS In Fire Zone 7A

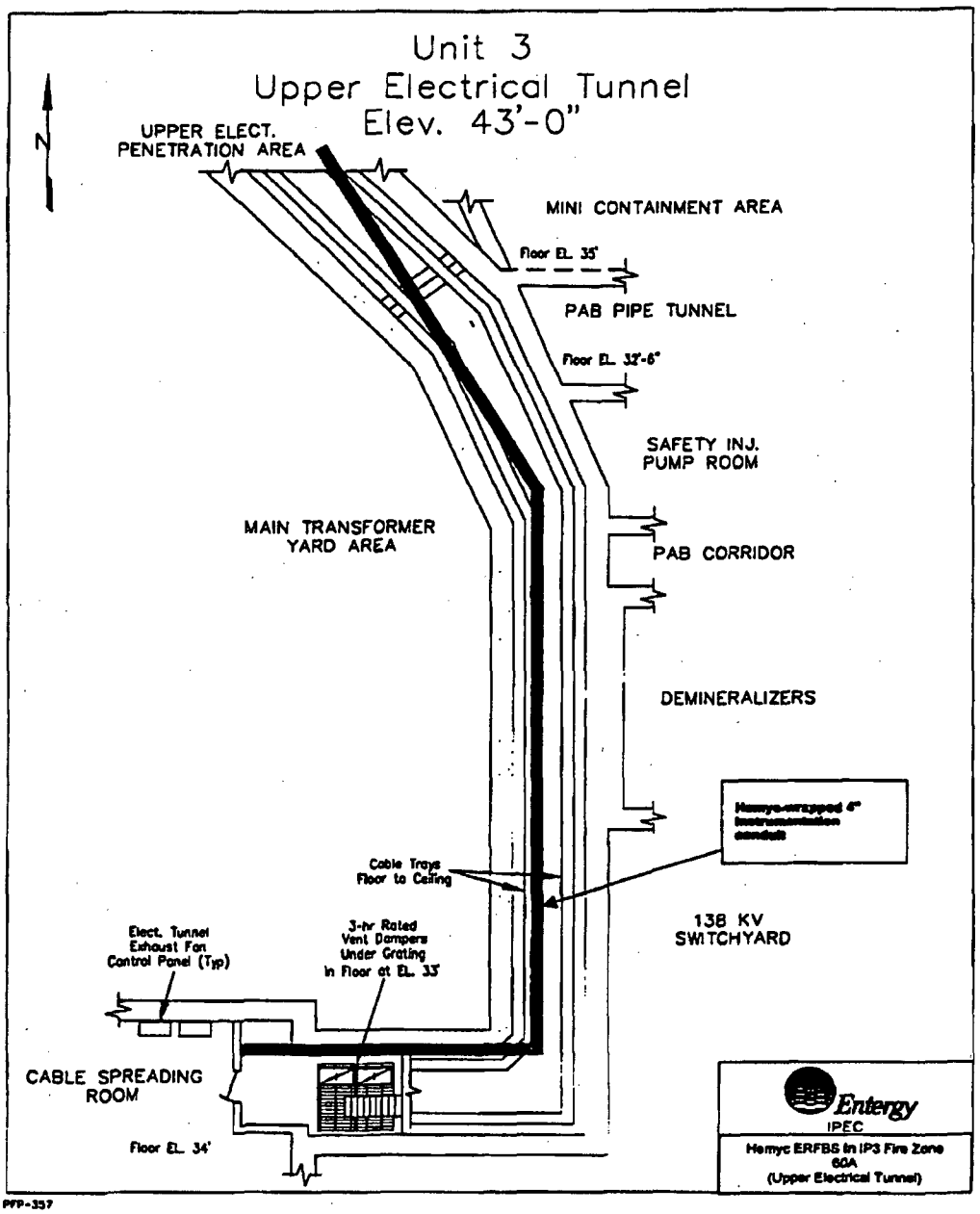

Figure 9.3: Hemyc ERFBS In Fire Zone 60A

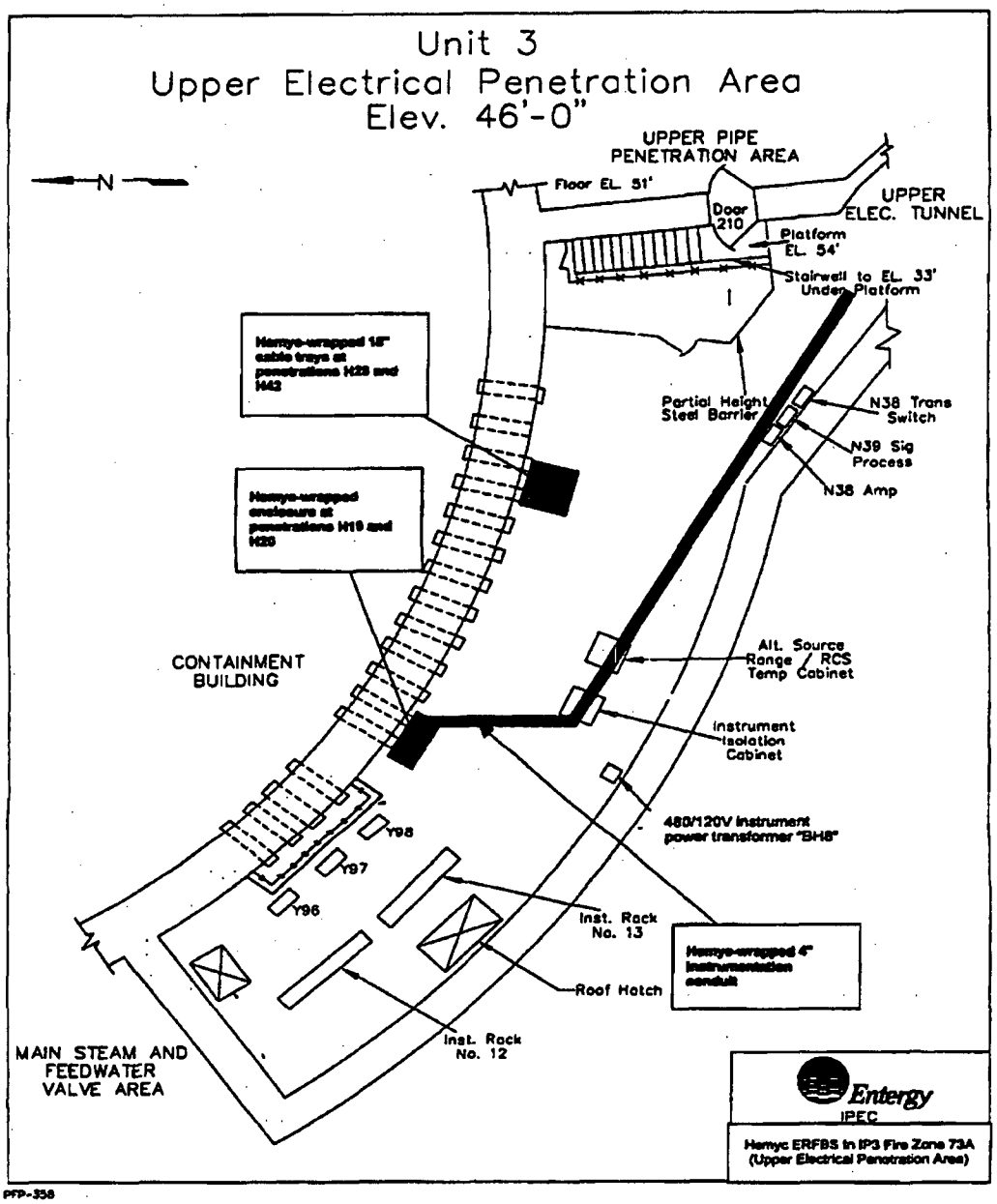

Figure 9.4: Hemyc ERFBS in Fire Zone 73A

Exhibit FP No. 7

UNITED STATES
NUCLEAR REGULATORY COMMISSION

In the matter of

ENTERGY NUCLEAR INDIAN POINT 2L.L.C)		
,ENTERGY NUCLEAR	)	License No. DPR 26 and
INDIAN POINT 3, L.L.C,	)	License No. DPR 64
And Entergy Nuclear Operations, Inc.	)	
and Entergy Northeast, Inc.,	)	Docket No. 50-247 and
regarding the Indian Point Energy Center	)	Docket No. 50-286
Unit 2 and Unit 3	)	
License Amendment Regarding Fire Protection Program		

FIRST DECLARATION OF ULRICH WITTE
PETITION FOR LEAVE TO INTERVENE, REQUEST FOR HEARING, AND CONTENTIONS REGARDING FIRE PROTECTION PROGRAM AT INDIAN POINT UNIT 3 AND UNIT 2

My name is Ulrich Witte. WestCAN, RCCA. PHASE, SIERRA CLUB, BEYOND NUCLEAR and New York State Assemblyman Richard Brodsky, have retained me under the auspices of the Indian Point Safe Energy Coalition as a consultant with respect to the above-captioned proceeding. I am a mechanical engineer with over twenty-six year's professional experience in engineering, licensing, and regulatory compliance of fire protection of nuclear commercial nuclear facilities. I have considerable experience and expertise in the areas of configuration management, engineering design change controls, and licensing

basis reconstitution. I have authored or contributed to two EPRI documents in the areas of finite element analysis, and engineering design control optimization programs. I have led industry guidelines endorsed by the American National Standards Institute regarding configuration management programs for domestic nuclear power plants. My 26 years of experience has generally focused on assisting nuclear plant owners in reestablishing fidelity of the licensing and design bases with the current plant design configuration, and with actual plant operations. In short, my expertise is in assisting problematic plants where the regulator found reason to require the owner to reestablish competence in safely operating the facility in accordance with regulatory requirements. My curriculum vitae is attached hereto as Attachment A.

I submit the following comments in support of each coalition stakeholder in asserting the unlawful and frankly dangerous exemption to fire protection federal rules that was granted by the Nuclear Regulatory Commission and published on October 4th, 2007 in the federal register

I. The exemption granted by the commission allows the licensee to take manual action in suppressing a fire that is outside the limitations of the rule.

In fact the exemption granted requires that in order for the reactor to maintain controlled criticality during and after a fire in either one of two electrical tunnels, the fire would have to be manually extinguished within 24 minutes. This

time limit starts from first detecting the fire, then summoning the brigade, responding, and amongst various actions de-energizing the 480 volt e bus, and then fully suppressing the burning cable insulation in order to protect electrical cables from ground faults. In addition, these actions must in less than 24 minutes prevent shorting power cables from spuriously initiating other circuits to prevent inadvertently open or close valves inside containment.

These actions involve a brigade donning nomex gear, donning scott air packs, organizing a team that in accordance with the IP3 Technical Requirements Manual Exhibit FP No. 15 which will have only limited trained reactor operator assistance, entering an electrical tunnel, and then suppressing the fire knowing full well that energized circuits must be maintained for one train, while the burning trays containing the redundant cable only one foot away are de-energized and the fire suppressed prior to damaging cables. The brigades confidence in spraying water onto the electrical fire will further slow an already unrealistic response of a sprint to suppress the fire making full extinguishment in less than 24 minutes entirely unrealistic.

Where this an "ordinary" electrical fire involving high voltage or medium voltage combined with high amperage equipment, without threat to safe operation of the reactor core, the suppression scenario without the unfathomable time constraint may be plausible, but accomplished with deliberate actions that

minimize risk to fire brigade members. But not in 24 minutes from ignition. See for example, NUREG-1852, "Demonstrating The Feasibility And Reliability Of Operator Manual Actions In Response To Fire," October 2007.

> As to the aforementioned analysis, and as delineated in greater detail in subsequent sections, determining whether there is enough time available to perform the operator manual action should account for potential circumstances, such as (1) the potential need to recover from or respond to unexpected difficulties associated with instruments or other equipment, or communication devices, (2) environmental and other effects that are not easily replicated in a demonstration, such as radiation, smoke, toxic gas effects, and increased noise levels, (3) limitations of the demonstration to account for all possible fire locations that may lead to the need for such operator manual actions, (4) inability to show or duplicate the operator manual actions during a demonstration because of safety considerations while at power, and (5) individual operator performance factors, such as physical size and strength, cognitive differences, and the effects of stress and time pressure. The time available should not be so restrictive relative to the time needed to perform the actions that personnel are not able to recover from any initial slips or errors in conducting the actions (i.e., there is some "recovery" time built in, should it be needed).

Exhibit FR No. 16.

II. The exemption granted by the commission rely on their belief of a low probability of the occurrence of the event, which is outside the parameters for Appendix R Rule.

3. When enquiring as to how the Commission was able to grant this exemption with members of the NRC staff, the response was that the industry was moving away from deterministic approaches for managing fire threats to reactor core to a probabilistic analysis. I was told that even though the even would have severe consequences of this fire, the probability of it occurring was low enough by the

licensees analysis, that the exemption was justified.

With this kind of rationale, why bother to protect redundant cables at all? Essentially, by this approach no protection could be found acceptable for the tunnel, with no manual suppression, with no detection, and no actual preparedness in the event of a fire.

In 1986 I was responsible for fully implementing the requirements of 10CFR50.48 and Appendix R to the Ranch Seco Nuclear Power Station owned by the Sacramento Municipal Utilities District.

As the Project Engineer, I was responsible for establishing compliance to Appendix R for the plant. This was a monumental effort, given that the licensee had delayed implementation, and in approximately one year, the physical changes to the facility had to be designed, implemented, and where possible tested to meet sections III G of appendix R. Numerous procedures had to be developed from scratch, and operators required extensive training on successful safe shutdown of the facility with a fire initiated from any area of the plant that threatened safe shut down equipment. It was beyond comprehensible to think that any competent and reasonable operator would and should be required to take manual actions so desperately necessary that if not accomplished in 24 minutes with full suppression, the fire could have led to core melt. Plant management, the NRC Inspection Team, and NRR a like would each have declared a program crediting actions such as

those as highly unrealistic, and would have never accepted them as successfully implementing Appendix R for the plant. An exemption request for this was unthinkable.

It was ludicrous then, and it is ludicrous now. Of note is that this project was inspected by the NRC and was found as having zero open items regarding implementation of Appendix R.

III. Use of alternative analysis under NFPA 805 as an escape from the deterministic rules enacted in 1979 and contains assumptions that counter recent codified law relevant to fire and Design Basis Threats

Use of NFPA 805 is being pushed by industry and the regulator alike. When the regulator acknowledged in 2002 the substantial non-compliance of numerous licensee holders to the requirements of Appendix R, in particular not crediting manual actions to maintain safety system and safe shutdown capability for one hour in certain areas, the alternative approach was invoked. The alternative approach fails to include the revised baseline assumptions required in 10CFR73.1 which includes fire induced events by personnel inside the facility having both knowledge of and target awareness of the consequences of the fire. The exemption granted requires an amended Safety Evaluation by the Staff, and as a result constitutes an unacceptable change to the operating license DPR No. 64 to the Indian Point Unit 3 Facility.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed this 3rd day of December, 2007.

Ulrich K. Witte

State of New York)
)ss.:
County of Rockland)

On the 3rd day of December, in the year 2007 before me, the undersigned, personally appeared.
Ulrich Witte, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her their signatures(s) on the instrument, the individual(s) or the person upon behalf of which the individual(s) acted, executed the instrument.

SUSAN HILLARY SHAPIRO
Notary Public - State of New York
No. 02SH6060466
Qualified in Rockland County
My Commission Expires June 25, 2011

Notary Public

Exhibit FP No. 8

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

May 11, 1995

Mr. Leslie M. Hill, Jr.
Resident Manager
New York Power Authority
Indian Point 3 Nuclear Power Plant
Post Office Box 215
Buchanan, NY 10511

SUBJECT: SPECIAL INSPECTION TO REVIEW FIRE PROTECTION AND APPENDIX R RESTART ITEMS, INSPECTION REPORT NO. 50-286/95-81

Dear Mr. Hill:

This refers to the team inspection led by Mr. R. A. Skokowski of this office from January 30 through March 24, 1995, at the Indian Point 3 Nuclear Power Plant, Buchanan, New York, and at the NRC Region I office in King of Prussia, Pennsylvania. The inspection focused on the adequacy of your efforts related to the resolution of restart issues identified in the "Restart Action Plan." Particularly, issues pertaining to your fire protection and Appendix R programs, and previously identified issues resulting from the electrical distribution system functional inspection (EDSFI) were reviewed. Mr. Skokowski discussed the findings of this inspection with you and/or members of your staff on February 10 and 17, and March 24, 1995.

The inspection was directed towards areas important to public health and safety. Areas examined during this inspection are described in the NRC inspection report enclosed with this letter. The inspection consisted of selected examinations of design documents, procedures, representative records, interviews with personnel, and observations made by the team.

Based on the team's review, your actions were considered appropriate to close both the fire protection/Appendix R and EDSFI-related restart issues. However, with respect to the fire protection/Appendix R issue, the team noted that compensatory fire watches, in place for the penetration seals, are required until the completion of your effort to verify that the generic information used in your fire seal analysis appropriately represents the cables installed at Indian Point 3 or that the cables in question are otherwise qualified. This issue was discussed during several telephone conversations between NRC and members of your staff, concluding with a conversation on May 10, 1995, between Mr. Ruland and yourself. During this conversation, you committed to maintain compensatory fire watches as described above. Additionally, during this conversation, Mr. Ruland confirmed your commitment to complete all fire protection and Appendix R-related startup labeled ACTS items and work requests prior to plant restart.

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

REPORT/DOCKET NO:	50-286/95-81
LICENSEE:	New York Power Authority
FACILITY:	Indian Point 3 Nuclear Power Plant
LOCATION:	Buchanan, New York
DATES:	January 30, 1995 - March 24, 1995
INSPECTORS:	R. Bhatia, Reactor Engineer, DRS L. Harrison, Reactor Engineer, DRS A. Singh, Fire Protection Engineer, NRR R. Skokowski, Reactor Engineer, DRS E. Connell, Sr. Fire Protection Engineer, NRR

TEAM LEADER: William H. Ruland/RA 5/11/95
Richard A. Skokowski, Reactor Engineer — Date
Electrical Section
Division of Reactor Safety

APPROVED BY: William H. Ruland 5/11/95
William H. Ruland, Chief — Date
Electrical Section
Division of Reactor Safety

EXECUTIVE SUMMARY

Purpose: The purpose of this inspection was to review and determine the adequacy of the licensee's follow-up actions to resolve fire protection/Appendix R and electrical distribution system functional inspection (EDSFI) follow-up issues categorized by the NRC as restart issues. Acceptable solution of these issues were included in the Indian Point 3 "Restart Action Plan" (RAP) and was a prerequisite for the plant to start-up for normal operation. The NRC based the acceptability of the issues on information provided by the licensee and independent verifications of selected portions of that information.

RAP Item II.3; Fire Protection/Appendix R Programs

Overall, the team considered New York Power Authority's (NYPA) efforts to improve and gain control of the fire protection/Appendix R programs to be effective. The majority of work items reviewed were found to be extensive and well thought-out. The team did identify a few discrepancies, however. These discrepancies did not detract from the overall good performance.

Based on the team's review, NYPA's actions were considered appropriate to close the fire protection/Appendix R restart issue, with the compensatory fire watches in place for the penetration seals until the completion of their evaluation for cable ignition temperatures associated with Unresolved Item 50-286/93-24-03.

To address outstanding fire protection and safe shutdown issues, NYPA developed the "Indian Point Unit 3 Appendix R & Fire Protection Improvement Plan." To accomplish the objectives of this improvement plan, NYPA developed a number of short-term issues, which were required for restart, and other long-term issues tracked for implementation following start-up. The details of the team's review of the short-term issues is included in this report. The team also reviewed previously identified violations, unresolved items, Licensee Event Reports (LERs), and other issues. These other issues were related to the fire protection and Appendix R programs and included management oversight, the reactor coolant pump (RCP) oil collection system (OCS), the Appendix R emergency diesel generator (EDG), and system certifications.

Fire Protection/Appendix R Management Oversight

The team considered the development of the Fire Protection/Appendix R Task Force and the oversight committee as an aggressive initiative for providing technically appropriate resolutions to the fire protection issues.

The development and assignment of a safety and fire protection general supervisor was also considered a good initiative. This assignment provided needed planning, scheduling, and additional management oversight of the Fire Protection Program.

Reactor Coolant Pump Oil Collection System

The team evaluated the RCP OCS to verify compliance with Appendix R. Included in this evaluation was the performance of system walkdowns and review of applicable design and implementation documents. During the walkdowns, the team identified several material deficiencies which were subsequently corrected by NYPA. Based on the team's review of the OCS design and installation, the team concluded that the OCS was adequate to meet the requirements of 10 CFR Part 50, Appendix R, Section III.O. However, the team determined that additional management attention was needed to ensure that concerns identified during this review are properly addressed.

During the review of a recent modification to the RCP OCS, a concern regarding the use of engineering change notices (ECNs), for material substitutions and technical evaluations to support substitutions, was identified. This issue was determined to be an unresolved item. Additionally, the team identified that there was a previous concern by NYPA regarding the use of ECNs at FitzPatrick approximately two months earlier. This issue was discussed with various organizations at Indian Point 3 (IP3). These discussions indicated that no means had been established to ensure that information is shared between IP3 and FitzPatrick for common NYPA processes.

Removal of the Fire Protection Technical Specification Requirements

On February 8, 1994, the detailed requirements associated with fire protection were removed from technical specifications (TS) and re-established through administrative controls in TS 6.8.1.j. This TS required that written procedures shall be established, implemented, and maintained covering the fire protection program. The team identified that the required procedures were not in place until after the changes to the TS were completed. Subsequently, actions were taken by NYPA staff to address this issue and to assure control the fire protection program had not been compromised. Additionally, a review of the operating logs performed by NYPA staff identified no conditions that could have caused limiting conditions for operation (LCO) to be entered. This issue was considered a non-cited violation of the TS requirements.

Conclusion - RAP Item II.3; Fire Protection/Appendix R Program

Based on the team's review, RAP Item II.3, pertaining to the Indian Point 3 Fire Protection/Appendix R Programs, is closed.

RAP Item II.19; EDSFI Items

Unresolved Item 50-286/91-80-10 EDG Transient Loading

Several calculations, studies, and tests associated with this effort were reviewed. Based on this review, the team considered NYPA's actions pertaining to EDG transient loading acceptable for restart. However, the associated Unresolved Item, 50-286/91-80-10, will remain open until completion of the final validation. The team considered NYPA's efforts pertaining to the EDG

transient loading completed to date, extensive. Additionally, their retesting of the safety injection pump motor, to verify that recent work on the pump did not impact the motor model, was considered by the team as an example of a good questioning attitude.

Unresolved Item 93-18-02 EDG kW Meter Tolerance for Load Management

This issue was reviewed by the team and found to be thoroughly evaluated by the licensee. The completed work by NYPA to develop the associated calculation was considered by the team to be an example of good communications between the engineering and operations departments. This item is considered closed.

Conclusion - RAP Item II.19; EDSFI Items

Based on the team's review, RAP item II.19, pertaining to EDSFI Items, is closed.

TABLE OF CONTENTS

TABLE OF CONTENTS (CONT'D)

TABLE OF CONTENTS (CONT'D)

DETAILS

1.0 INTRODUCTION

The purpose of this inspection was to review and determine the adequacy of the licensee's follow-up actions to resolve fire protection/Appendix R and electrical distribution system functional inspection (EDSFI) follow-up issues, categorized by the NRC as restart issues. The Indian Point 3 "Restart Action Plan" (RAP) stated that acceptable solution of these issues was a prerequisite for plant start-up. Each item was uniquely identified by a RAP number in the plan, and this number was used in this report to identify the associated NRC review and evaluation. The RAP item, associated with fire protection/Title 10 Code of Federal Regulations (CFR) Part 50, Appendix R issues, is Number II.3 and the RAP item associated with EDSFI issues is Number II.19.

Inspection Methodology

The team based the acceptability of the issues on information provided by the licensee and independent verification of selected portions of this information. The information provided by the licensee included evaluations, reports, calculations, procedures, and other applicable documents. The team verified this information through selected system walkdowns, personnel interviews, independent calculations, and comparison to industry standards and NRC regulations. The items selected for independent review were based on safety significance, quality of the licensee evaluation of the issues, and scope of the licensee's review.

2.0 FIRE PROTECTION/APPENDIX R RESTART ISSUES (64150)

The team examined several issues related to both the fire protection and Appendix R programs at Indian Point 3 (IP3) to determine the acceptability for restart. This examination included previously identified violations, unresolved and inspector follow-up items, Licensee Event Reports (LERs), review of the reactor coolant pump (RCP) oil collection system (OCS), the Appendix R emergency diesel generator (EDG), system certifications of selected fire protection and Appendix R systems, and management oversight in the areas of fire protection and Appendix R programs.

2.1 Short-Term Fire Protection/Appendix R-Related Corrective Actions (Inspector Follow-up Item (IFI) 50-286/93-24-01)

To address outstanding fire protection and safe shutdown issues, New York Power Authority (NYPA) developed the "Indian Point Unit 3 Appendix R & Fire Protection Improvement Plan." To accomplish the objectives of this improvement plan, NYPA developed a number of short-term issues, required for restart, and other long-term issues. Additionally, these short-term and long-term issues were included in the Indian Point Unit 3 Performance Improvement Plan (PIP) as Items 177.1 and 177, respectively. Subsequently, the PIP was revised and renamed the Restart and Continuous Improvement Plan (RCIP). Both the PIP and the RCIP were submitted to the NRC in January 1993 and May 1994, respectively. The team reviewed the short-term issues, as tracked by the original PIP numbers. These reviews are described below. The review of the long-term issues will be completed during future NRC inspections.

2.1.1 PIP 177.1 Task 5 (RCIP Task #1); Impact of Modifications on IP3 Safe Shutdown Capability (Unresolved Item 50-286/93-24-05)

Overview

This task and Unresolved Item 50-286/93-24-05 pertained to the development of a fire protection/Appendix R modification procedure to assure adequate control of plant modifications. At the conclusion of the October 1993 fire protection and Appendix R Inspection 50-286/93-24, the inspectors identified that NYPA had no adequate measures in place to verify and review the impact of modifications on the safe shutdown capability of the plant. NYPA committed to establish a method to review all outstanding modifications and determine the impact of changes on the fire protection and Appendix R programs, and related documents, prior to plant restart.

Details

During this inspection, the team noted that NYPA had completed the review of the outstanding field modifications installed in the plant up through January 1993. NYPA, with the assistance of their contractor (Engineering Planning and Management (EPM)), Inc., as a part of this effort, had reviewed the impact of these modifications on safe shutdown capability and the impact on fire protection documents. According to the licensee, all applicable data from previously installed modifications had been updated in the Appendix R Analysis and Fire Hazard Analysis documents, with the exception of 14 modifications listed on their configuration controlled data base. In addition, the team noted that the impact of the remaining and ongoing modifications on fire protection and Appendix R-related documents was being tracked under the established procedure to assure timely updating of these documents.

The team reviewed NYPA's issued procedure ESM, FPES-04B, Revision 0, dated April 11, 1994, to evaluate the impact of ongoing modifications. The team noted that this procedure provided adequate guidance to review, evaluate, and control the process for updating Appendix R-related documents during plant modifications to ensure compliance with 10 CFR 50 Appendix R requirements. The procedure requires that the responsible design engineer complete a fire protection and Appendix R compliance checklist to ensure the design applicability to these requirements. The checklist is used to determine whether the design requires a detailed fire protection review. If needed, a fire protection engineer performs the detailed review. Based on the review of this established procedure and sample review of the completed recent modification checklist input, the team concluded that adequate controls were established to ensure that ongoing modifications and future modifications are adequately evaluated against the requirements of Appendix R.

The team noted that the installed modifications were reviewed by NYPA for fire protection impact on both the Appendix R Analysis and Fire Hazard Analysis. These modifications were listed in Attachment B of these documents.

The team reviewed two randomly selected modifications listed in each document to ensure that data was valid and appropriate. In addition, a sample of the recently completed modification fire protection checklist were reviewed and no concerns identified. The team concluded that the modification fire protection program review checklist was being completed in accordance with the established administrative procedures by the responsible design and fire protection engineers.

Conclusion

Based on the above review, the team concluded that adequate measures had been established to identify, review, and update the fire protection documents. Additionally, the team found that the applicable fire protection documents were appropriately updated to include previously-installed modifications. The team concluded that NYPA had demonstrated that adequate controls had been established and implemented in this area to restart the plant at this time. PIP 177.1 Task 5 and Unresolved Item 50-286/93-24-05 are closed.

2.1.2 PIP 177.1 Task 6 (RCIP Task #2); Primary Auxiliary Building (PAB) Heating, Ventilating, and Air Conditioning (HVAC)

Overview

The purpose of this task was for NYPA to evaluate, update, and improve the existing Primary Auxiliary Building HVAC calculations to document the consequences of a PAB loss of ventilation. In addition, the cables and components associated with the PAB ventilation were required to be assessed from an Appendix R compliance perspective.

Details

During this inspection, the team noted that NYPA had further evaluated the results of the completed PAB loss of ventilation calculations. The licensee developed test Procedure ENG-560, which was conducted on November 21, 1994, to evaluate the rise in air temperature in the PAB and its effect on equipment, including the motor control center (MCC), component cooling water (CCW), and charging pump rooms following a loss of ventilation that could occur during a postulated loss of coolant accident (LOCA) and Appendix R fire condition.

Based on the heat generation analysis and extrapolation of data obtained during the test, the licensee determined that, following a loss of PAB ventilation, the air temperature in the MCC area at the 55 ft. elevation would increase approximately 2°F in one hour during the LOCA, and then reach steady state conditions. This small temperature increase was due to the reduced electrical load that would be present during this plant condition. In the case of a postulated fire condition, when offsite power would be available, the licensee determined that the rise in air temperature would increase approximately 9°F in the MCC area after one hour. Based on the small rise in temperature compared to the original higher calculated, the licensee concluded that the original calculation results were overly conservative.

NYPA indicated that the temperature profiles calculated in the latest UE&C Calculation (6604.327-6-PAB-002, Revision 2), showed that all safe shutdown equipment in the PAB areas, except the thermal overload relays of the MCCs, would continue to remain operable for at least four hours following a loss of ventilation. Therefore, the temperature profiles calculated in the updated calculations were appropriately conservative.

Through review of licensee documents, the team determined, based on this review, that the cables and components associated with the PAB ventilation were assessed by NYPA from an Appendix R perspective and found to be acceptable.

Conclusion

Based on the above completed actions, the team concluded that the licensee had adequately resolved and completed the above task. Therefore, PIP 177.1 Task 6 is closed.

2.1.3 PIP 177.1 Task 7 (RCIP Task #3); Fire Wrap Adequacy

Refer to Section 2.3 for discussion and closure of this item.

2.1.4 PIP 177.1 Task 8 (RCIP Task #4); Installation of Marinite Board in Containment

Refer to Section 2.3 for discussion and closure of this item.

2.1.5 PIP 177.1 Task 9 (RCIP Task #5); Adequacy of Fire Doors

Overview

The purpose of this PIP Item 177.1 Task 9 was to perform a National Fire Protection Association (NFPA) Standard 80 code compliance review of installed fire doors and to take appropriate corrective actions for the nonconformances and deviations identified.

Details

During the 50-286/93-24 inspection, the inspectors concluded that PIP Task 9 was incomplete due to the hardware repairs that were not complete. In response to this task, the licensee performed a code compliance study to ensure that the fire-rated doors installed in the plant meet NFPA Code 80, "Standard for Fire Doors and Windows." This code compliance study was performed by an independent contractor. The study identified conditions that were not in strict compliance with the requirements of the standard and provided recommendations to correct the noted noncompliance issues. For those

items requiring more extensive efforts to achieve strict compliance, the recommendations made by the contractor were evaluated, and appropriate actions were taken to bring the concerned doors into compliance. The following is the summary of the noncompliance conditions identified:

(1) Minor maintenance items such as small holes in the surface of doors and frames, doors that would not close and latch when released from an open position, missing or inoperative top and/or bottom bolts on the inactive leaf of double swinging fire doors, painted or broken fusible links on doors, and unlabeled doors and frames.

(2) Gaps between doors, frames, and door latches with less than the required latch throw.

(3) Unlabeled gasket material installed on various doors and/or frames.

(4) Fire doors which were not included in procedure FP-19, "Fire Door Inspection."

During this study, the contractor found 10 of the 100 Appendix R doors installed for use as a 3-hour fire barrier. The licensee stated that although the above issues were not in strict compliance with the requirements of NFPA 80, they would perform their intended function for providing separation of fire areas as required by Appendix R. The team noted that the licensee had taken all the appropriate corrective actions to bring these doors into compliance. Additionally, the team observed several fire doors during plant walkdowns and identified no concerns.

Conclusions

Based on the above review, the team concluded that the licensee has taken appropriate corrective action to resolve this task. Therefore, this task is closed.

2.1.6 PIP 177.1 Task 10 (RCIP Task #6); Penetration Seal Adequacy (Unresolved Item 50-286/93-24-03 & LER 93-29)

Overview

The purpose of Task 10 was to perform a baseline inspection of 100 percent of plant fire barrier penetrations, document appropriate information, and initiate appropriate repairs and corrections. Fire barrier penetration seal maintenance and repair procedures were to be reviewed by the licensee and revised as necessary prior to start-up. During the 50-286/93-24 inspection, the inspectors created Unresolved Item 50-286/93-24-03, associated with this task pending the licensee's verification of the cable insulation temperature to assure that the maximum unexposed side temperatures were sufficiently below the cable insulation ignition temperature. Also related to penetration seal adequacy, NYPA submitted LER 93-29 regarding nonfunctional penetration fire seals and fire barriers located in the walls between EDG cells. To address the adequacy of penetration seals, the team reviewed this PIP task item, Unresolved Item 50-286/93-24-03 and LER 93-29.

Details

The team reviewed Engineering Acceptance Test ENG-527, "Fire Barrier Inspections," and the significance of any deficiencies identified during the inspection effort. The licensee inspected approximately 1200 fire seals of which 8% of the seals were judged to be non-functional and the remaining 92% judged to be functional. Approximately 450 of the 1200 fire seals inspected were repaired. The majority of the repaired were completed to provide a means to impede mechanical damage to seals located in high traffic areas. In addition, some of the seals were reworked to enhance their integrity and maintain consistency between installed seal configurations and typical design details. The fire seals which were repaired were determined by the licensee to be functional. For example, enhancement repairs included: filling of minor holes or voids in the seal surface, repairing existing damming material, repairing the flamemastic layer of certain fire stops, installing a protective elastomer cap on seals in high traffic areas, adding additional seal material to the existing seals, and installing smoke and hot gas seals to enhance the provided level of protection.

The licensee has established procedures associated with the installation and repair of silicone foam, silicone elastomer, and flamemastic fire stops. The team's review of these procedures did not identify any concerns. The team also reviewed the qualification of the installers and did not identify any concerns.

Additionally, the team reviewed LER 93-29 and performed a walkdown of the penetrations separating the EDGs and verified the modification completed to address these previously improperly installed penetration fire seals. The team did not identify any further concerns.

The team reviewed the licensee's evaluation provided in response to Unresolved Item 50-286/93-24-03 titled, "FIRE SEAL ANALYSIS - Self Ignition Temperature of Cable Insulation as it Relates to the Design of Fire Seals," dated January 25, 1995. Evaluation No. IP3-ANAL-FP-01392, Revision 0. The licensee concluded in this evaluation that the self-ignition temperature of the cable insulation is not less than 785°F, and that this temperature is sufficiently above the 700°F maximum allowable unexposed surface temperature criteria for penetration seal designs at IP3. The licensee based this conclusion on generic cable flammability data published by Electric Power Research Institute (EPRI). During a telephone conference with NYPA personnel, Region I and Nuclear Reactor Regulation (NRR) staff on April 3, 1995, the licensee stated that they had determined that the cables at IP3 are "similar" to the cables referenced in the EPRI reports, but they could not provide reasonable assurance, such as manufacturer, date of manufacture, and cable type, that the cables specified in the EPRI report are representative of the cables installed at IP3. The licensee also stated that plant-specific cable flammability data was not available from the manufacturer. Due to the broad range in flammability data for cables of "similar" construction, and the different test protocols for obtaining the flammability data, and the licensee was not able to provide reasonable assurance that the data referenced in the licensee's January 25, 1995, evaluation was applicable to cables installed at IP3; therefore, the team was concerned with the generic cable data used in the

licensee's fire seal analysis to adequately represent the cables installed at IP3. Subsequently, telephone conversations with NYPA, NRR, and Region I were held on April 7, April 28, and May 4, 1995, to discuss NYPA's actions to address this concern. During this conversation, NYPA stated that they intended to do further research to verify the applicability of the generic information used in their evaluation. Additionally, NYPA intends to test a sample of installed cables to verify the ignition temperatures of the cables if needed. This item remains unresolved pending the completion of NYPA's effort and subsequent NRC review. The licensee has implemented fire watches in all plant areas where the penetration seals in question are located. These compensatory measures, coupled with the other elements of the licensee's fire protection program, ensure an adequate level of fire safety is provided. The team determined that the licensee's actions were acceptable for restart.

Conclusions

Based on the above, the team concluded that NYPA has taken appropriate corrective actions to repair the degraded seals at IP3. Therefore, PIP 177.1 Task 10 is closed. Additionally, the team reviewed LER 93-29 and found it to be appropriate. However, the associated Unresolved Item 50-286/93-24-03 remains open pending the completion of the licensee's effort and subsequent NRC review. The compensatory fire watches, coupled with the other elements of the licensee's fire protection program, ensure an adequate level of fire safety is provided for restart.

2.1.7 PIP 177.1 Task 11 (RCIP Task #7); Cable Tunnel Suppression System

Overview

The purpose of this PIP Item 177.1 task was to review the electrical cable tunnel suppression system design and previous analyses for establishing suppression adequacy to meet Appendix R safe shutdown concerns.

Details

Amendment No. 24 to the Indian Point Unit 3 Facility Operating License No. DPR-64 required the licensee to complete Modifications 3.1.1 through 3.1.14 of the NRC Safety Evaluation Report (SER), dated March 6, 1979. Modification 3.1.8 required installation of dry-pipe preaction-type sprinkler systems to provide coverage of all trays in the electrical tunnels and electrical penetration area that were not already covered by the existing system. It was the NRC's staff position that the system would comply with NFPA-15.

During the October fire protection inspection (No. 50-286/93-24), the inspectors reviewed the sprinkler drawings and hydraulic calculations for the cable tunnel suppression system. At that time, the inspectors also verified the installation of the sprinkler system by performing a walkdown of the electrical cable tunnel. Based on review of the SER, hydraulic calculations, and walkdown of the system, the team concluded that the sprinkler system installed was adequate to control and/or extinguish a fire. Therefore, this suppression system was considered acceptable for plant restart.

Conclusions

Based on the above in-depth inspection results and NRC acceptance of actions taken by the licensee to complete this task, the team concluded that the electrical cable tunnel sprinkler system was adequate to control and/or extinguish a fire, and was determined to be acceptable for plant restart at this time. Therefore, PIP 177.1 Task 11 is closed.

2.1.8 PIP 177.1 Task 12 (RCIP Task #8); Instrument Sensing Line Separation

Overview

The stated purpose of this PIP Item 177.1 task was to review the separation of instrumentation lines in containment, along with cables, for effects of fire on instrument capability.

Details

This task pertains to the potential effect of fire on the performance of steam generator and pressurizer level instrumentation. This issue was identified by the licensee in their 1984 reanalysis to achieve safe shutdown conditions of the reactor in the event of fire within the non-inerted containment of IP3. Based on the 1984 configuration of sensing lines within containment for the steam generator and pressurizer level instruments, it appeared that they did not satisfy the requirements of Section III.G.2, Paragraphs D, E, and F. If an exposure fire was postulated to occur within containment, exposure of the instrument sensing lines to the resulting elevated temperatures may result in a loss of accuracy and operability of these instruments, or cause previously unanalyzed spurious actuation due to the generation of false pressurizer or steam generator level signals.

During the previous fire protection inspection in October 1993, the licensee stated that their evaluation of this concern had concluded that, due to the low probability of fire within the containment fire area, the low combustible loading in the area, and other physical aspects of the plant design and construction such as the routing of instrument sensing lines in steel Uni-Strut supports, an adequate technical basis exists to seek an exemption from the specific technical requirements of Appendix R, Section III.G.2.d, e, and f. Therefore, this task remained open pending submitting an exemption request to the NRC Office of Nuclear Reactor Regulation.

The team noted that the licensee had submitted the required exemption request to the NRC office per their letter, dated November 30, 1993, and supplemental letter dated July 6, 1994. By letter, dated January 5, 1995, NRC granted to IP3 the above exemption from the requirements of 10 CFR Part 50, Appendix R, paragraph III.G.2.f, to the extent that redundant wide-range steam generator water level sensing lines and the redundant pressurizer level sensing lines, located inside containment, need not be separated by noncombustible radiant energy shields.

Conclusion

Based on review of the above letters, the team concluded that the licensee had adequately completed the above committed task. Therefore, PIP 177.1 Task 12 is closed.

2.1.9 PIP 177.1 Task 13 (RCIP Task #9); Adequacy of Fire Dampers

Overview

The purpose of this PIP Item 177.1 task was to perform an NFPA 90A code compliance review of installed fire dampers and to make recommendations on nonconformances and deviations.

Details

During the 1993 fire protection inspection, licensee representatives indicated that the following non-Appendix R fire wall fire dampers were not inspected as required by their commitments presented in their fire protection plan. This fire protection plan was established to meet Appendix A to Branch Technical Position (BTP) 9.5-1:

DAMPER NUMBER	FIRE AREA	LOCATION
Number 6	CTL-3/11& CTL-3/35A	33 foot of the Control Building
Number 29	PAB-2/8A& PAB-2/10A	15 foot elevation of the Primary Auxiliary Building
Number 32	PAB-2/5A& PAB-2/9	34 foot elevation of the Primary Auxiliary Building
Number 38	PAB-2/5& PAB-2/21A	55 foot elevation of the Primary Auxiliary Building
Number 39	PAB-2/6& PAB-27	55 foot elevation of the Primary Auxiliary Building
Number 40	PAB-2/17A& PAB-2/7	73 foot elevation of the Primary Auxiliary Building
Number 41	PAB-2/17A& PAB-2/20A	55 foot elevation of the Primary Auxiliary Building

In addition, the licensee stated that they were in the process of improving their fire damper surveillance program and the fire damper surveillance procedures. These procedures were to be revised to include the above-mentioned dampers and all other fire dampers for a drop test to be performed once a year.

During this inspection, the team noted that the licensee had completed the NFPA 90A Code Compliance Review of all dampers by November 1993. The team reviewed the code compliance effort and verified that the above fire dampers were included in this evaluation effort. The team noted that this portion of the damper effort was included in the code compliance record of air conditioning and ventilation systems, issued on May 27, 1994. Per discussion with the licensee and review of the documentation, the team ascertained that the only open issue remaining from this effort was to repair non-Appendix R fire damper No. 40 in the PAB building. Work Order 94-525 had been issued to replace the damper fuse link and missing blade locks. At this time, the licensee was awaiting parts delivery from their order. These replacements will be completed in the near future; however, the team determined that this repair was not essential for restart. The team also noted that the licensee had completed the fire damper drop test checks in May 1994, by means of the established work order process, to satisfy the TS requirements.

Per discussion with the licensee, the team found that the Preventative Maintenance (PM) Procedure FIR-005-FIR, pertaining to damper maintenance, is under development and is expected to be completed in March 1995. This issue was being tracked under their Action Commitment Tracking System (ACTS) Item 4108.

Based on the above review of related documentation and tests presented of this effort, the team concluded that the above dampers were adequately inspected and satisfied annual code PM and TS requirements.

Conclusions

The team concluded that this task was adequate for the restart of the unit at this time. Therefore, PIP 177.1 Task 13 is closed.

2.1.10 PIP 177.1 Task 14 (RCIP Task #10); Review of Safe Shutdown Procedures

Overview

Tasks 14 and 15 was initiated to document the review of Alternate Shutdown Procedures including cooldown. The purpose of these tasks encompassed the review of ONOP-FP-1A and ONOP-FP-1B to ascertain if there were any operational concerns with the methodology stated in these procedures.

Details

The licensee formed a task force which provided detailed oversight of the fire protection program at IP3. The task force reviewed these procedures to ascertain if there were any operational concerns with the methodology stated in these procedures. In addition, the licensee walked down both Off Normal Operating Procedures (ONOPs) to ensure manual operations called out by the procedures could be performed. The licensee verified that all the procedures worked as written. However, some procedure enhancements were identified and were discussed with the operations group for incorporation and revision.

The team discussed the enhancements with the operations group and did not identify any concerns. Included in this discussion was a review of selected portions of the following procedures:

- ONOP-FP-1, "Plant Fires," Revision 7;
- ONOP-FP-1A, "Safe Shutdown from Outside the Control Room," Revision 9;
- ONOP-FP-1B, "Cooldown from Outside the Control Room," Revision 6;
- ONOP-FP-1C, "Fire Area Evaluation," Revision 0;
- SOP-ESP-1, "Local Operations of Safe Shutdown Equipment," Revision 0; and
- SOP-EL-12, "Operations of the Alternate Safe Shutdown Equipment," Revision 9.

The team also reviewed Nuclear Safety Evaluation 95-3-098FP pertaining to the updates to the Appendix R safe shutdown procedures. Additionally, the team observed an in-plant drill requiring safe shutdown of the plant from outside the control room. The watch-team performed well, demonstrating familiarity with the plant equipment, and worked smoothly through the new procedures. As a result of the training of all watch-teams, NYPA identified a number of additional enhancements to be added to the procedures. At the end of this inspection, NYPA was in the process of evaluating these enhancements and stated their intentions to revise procedures as needed.

Conclusions

Based on the above review, the team concluded that the procedures provided sufficient guidance and detail to enable the operators to perform required actions. No deficiencies were identified during the procedures review. The licensee has taken appropriate corrective actions to resolve the issues stated in the above tasks. Therefore, these tasks are closed.

2.1.11 PIP 177.1 Task 15 (RCIP Task #11); Adequacy of Cold Shutdown Repair Procedures

Refer to Section 2.1.10 for discussion and closure of this item.

2.1.12 PIP 177.1 Task 16 (RCIP Task #12); Appendix R Commitments For Compliance

Overview

This task was required to be performed by NYPA to demonstrate that commitments they made to the NRC, as summarized in the Design Basis Licensing Database for 10 CFR 50, Appendix R, Sections III.G, J, L, and O, were properly implemented.

Details

During Inspection 50-286/93-24, the inspectors determined that NYPA had made progress in the review of their commitments to ensure compliance with all committed actions. Of 80 commitments reviewed, nine (9) could not be verified as complete and were being addressed by NYPA at the completion of that inspection.

During this inspection, the team verified the completion of those remaining nine items as documented in the internal NYPA memorandum ADM-QH93-343, dated August 27, 1993. The issues pertaining to these nine commitments were reviewed in detail, and the description of these reviews are contained in the following sections of this report:

- Generic Letter 86-10 Resolution (Section 2.1.21);
- Emergency Lighting Issues (Section 2.2);
- Fire Dampers (Section 2.1.9); and
- Quality Assurance Item Resolution (Section 2.1.20)

Conclusion

The team concluded that this task was adequate for the restart of the unit. Therefore, PIP 177.1 Task 16 is closed.

2.1.13 PIP 177.1 Task 17 (RCIP Task #13); Testing of Appendix R Alternate Shutdown Equipment

Overview

This PIP task was initiated to identify, document, and/or resolve concerns associated with the testing of Appendix R safe shutdown equipment.

Details

In response to this PIP task, NYPA performed an item-by-item assessment of each Appendix R-related component versus the testing or maintenance activity associated with the components. The scope of NYPA's review was based on those components required for safe shutdown as described in the plant fire operating procedures. The results of NYPA's review identified a few components without previously developed periodic testing requirements and a few other components without PM coverage. The testing concerns were addressed by developing test procedures and subsequent satisfactory completion of these tests. The PM concerns were directed to the IP3 Site PM Coordinator and processed in accordance with plant procedures. The team reviewed the results of NYPA's effort to address this PIP task item, including a sampled review of test procedures. The team determined that licensee corrective actions were appropriate.

Conclusion

The team concluded that this task was adequate for the restart of the unit. Therefore, PIP 177.1 Task 17 is closed.

2.1.14 PIP 177.1 Task 18 (RCIP Task #14); Appendix R Emergency Battery Light Issues

Refer to Section 2.2.1 for discussion and closure of this item.

2.1.15 PIP 177.1 Task 19 (RCIP Task #15); Development of Modification for Additional Emergency Lights Turbine and Administration Buildings

Refer to Section 2.2.2 for discussion and closure of this item.

2.1.16 PIP 177.1 Task 20 (RCIP Task #16); Safe Shutdown Communication Review

Overview

The purpose of this PIP Item 177.1 Task 20 was to review the safe shutdown communications, and the maintenance and testing of the communications equipment.

Details

In response to this task, the licensee developed a procedure which included the testing of communication equipment capabilities to perform the alternate shutdown procedures. During this inspection, the team reviewed test Procedure 3PT-R152, Revision 1, "Operability Test of Safe Shutdown Instrumentation," dated October 29, 1993. The licensee stated that the safe shutdown communications will be verified prior to start-up. The licensee also verified that radio communication links required for ONOP-FP-1A were established and functioned satisfactorily. The team did not identify any deficiencies in this area.

Conclusions

Based on the above review, the team concluded that the licensee has taken appropriate corrective actions to mitigate the above concern. Therefore, this task is closed.

2.1.17 PIP 177.1 Task 21 (RCIP Task #17); Development of Fire Protection Plan

Overview

The stated purpose of this PIP task was to develop and implement an updated fire protection program plan.

Details

During Inspection 50-296/93-24, the inspectors reviewed the recently developed "Fire Protection Plan for Indian Point 3 Nuclear Power Plant," Revision 0, dated June 30, 1993, and determined it did not provide sufficient detail to determine the extent and effectiveness of the Fire Protection Program. At the time of Inspection 50-286/93-24, it was NYPA's intention to revise the Fire Protection Plan; however, due to an ongoing reorganization within the NYPA engineering organization, NYPA has yet to complete the revisions to the Fire Protection Plan. NYPA has recently established a temporary task force to resolve the numerous outstanding fire protection/Appendix R-related issues. The guidance used by this task force was provided in Indian Point 3 Standing Order EDSO-01, "Closure of Open Fire Protection Items," Revision 1, effective November 11, 1994. Further discussions of this task force are provided in Section 2.7 of this report. Additionally, NYPA initiated ACTS Item 8170 to track the revision of the Fire Protection Plan upon completion of NYPA's reorganization. During this inspection, the team reviewed EDSO-01, and other fire protection/Appendix R-related procedures and documents, and found them to provide adequate guidance to define the Fire Protection Plan at Indian Point 3 for restart. The team noted the need for revision of the Fire Protection Plan pending completion of the task force's duties and the reorganization of NYPA staff, as stated in the above mentioned ACTS item.

Conclusions

Based on the established administrative controls in place, the team concluded adequate guidance was in place to control fire protection-related activities for restart. However, it was the team's understanding that the Fire Protection Plan will be revised upon the completion of the task force's assigned duties following the reorganization of NYPA staff. Therefore, this PIP task is closed based on NYPA's assurance that this task will be completed as described.

2.1.18 PIP 177.1 Task 22 (RCIP Task #18); Validation/Confirmation of IP3 Fire Hazards Analysis

Overview

The purpose of this PIP Item 177.1 task was to validate and confirm the Fire Hazard Analysis (FHA), to check assumptions regarding low fire loading, and verify the adequacy of updated combustible loading analyses to ensure that the FHA information is properly maintained for plant needs.

Details

During this inspection, the team noted that the licensee had updated the IP3 Fire Hazard Analysis (FHA) on January 11, 1995. This analysis superseded the existing fire/area zone analysis, Section 6.0 of the Fire Protection Program Manual (FPPM). The FPPM manual, issued by NYPA, was considered as a reference fire protection document that included field modifications installed since the last update in January 1991. NYPA, as discussed in Section 2.1.1, completed this work as a part of the PIP 177.1, Task 5 effort, after reviewing all the

outstanding field modifications and had updated the FHA and the Appendix R Analysis to reflect these changes. To date, with the exception of 14 recent modifications, all applicable data have been properly reflected in this report. Per discussion with the licensee, the team noted that ongoing remaining modifications, having impact on FHA and Appendix R documentation, was being tracked under the established configuration control procedure and applicable documents would be updated on an as-needed basis.

The team noted that the licensee's FHA document clearly defined the basic objective, scope, background, and regulatory requirements to provide adequate guidance for its users. In addition, a list of installed modifications reviewed by NYPA was contained in Appendix B of the FHA. The team noted that the licensee had included all areas containing equipment or systems necessary for achieving or maintaining cold shutdown during a single fire event, and those areas representing an exposure to any of the foregoing areas in this document. A sample review by the team of the FHA data, as-built design drawings, and observation of a computer simulation demonstration for a control room fire, revealed no concerns.

Conclusions

The team concluded that the licensee had adequately validated and incorporated the outstanding modifications for fire protection impact on the FHA and Appendix R documents. Therefore, this task is closed.

2.1.19 PIP 177.1 Task 23 (RCIP Task #19); Operations Review Group Item Review

Overview

This task was initiated to identify, document, and/or resolve Operations Review Group (ORG)-identified fire protection and Appendix R start-up issues.

Details

During this inspection, the team noted that NYPA collected all fire protection and Appendix R-related issues, including the ORG tasks, and listed them as either start-up issues or not. Each issue was provided an individual ACTS number.

The team noted that the NYPA ACTS program was established by Procedure AP-37.4. This system tracks and controls all NYPA's commitments, including required fire protection restart issues of all organizations. The team reviewed the ACTS open and closed items list for the fire protection and Appendix R issues and found no concerns. The team noted the open restart issues were adequately reflected as requiring completion prior to restart.

Conclusion

Based on the above review, the team concluded that the ORG tasks have been adequately incorporated into the ACTS program, and that the remaining open restart ACTS items will be completed prior to restart. Therefore, this item is closed.

2.1.20 PIP 177.1 Task 24 (RCIP Task #20); Quality Assurance Item Resolution (Violation 50-286/91-09-03 & Unresolved Item 50-286/93-04-07)

Overview

The purpose of this task was to identify, document, and resolve fire protection and Appendix R start-up issues identified by the Quality Assurance (QA) Department. Previous NRC Inspection Reports 50-286/91-09 and 50-286/93-04 and NYPA QA Audits FPA-89 and 90-42 documented the ineffectiveness of the tracking system and actions to resolve QA-identified deficiencies. Some of these deficiencies had existed since 1986. NYPA's failure to take timely corrective action on issues was indicative of a weakness in their ability to prioritize issues properly, assess them for safety significance and regulatory requirements, and establish appropriate compensatory measures. These issues were presented in NRC Violation 50-286/91-09-03 and again in Unresolved Item 50-286/93-04-07.

Details

As stated in NYPA's violation response letter, dated August 1, 1991, all previously required audits were completed by the Corporate Appraisals and Compliance Group Fire Protection Organization from the White Plains office. This group utilized independent procedures and processes, and did not have the items tracked within the Site QA Corrective Action Tracking Process. This means failed to allow for an effective escalation process or complete resolution of identified issues.

Corrective actions taken by the licensee included the implementation of one station-wide corrective action system, ACTS. This system was described in Administrative Procedure AP-37.4, Revision 0, "Action and Commitment," and was administered by the IP3 ORG. This system had been in place since November 1, 1993. The ACTS report notifies station department heads, general managers, and the resident manager of unresolved corrective action items weekly.

All items identified within the 1990 QA audit report that remain open, including the issues from 1986 through 1989, were captured in the ACTS. In addition, the QA organizations were found to require that all fire protection audits are performed in a formal, planned manner within the administrative framework of the site QA group. Three general manager positions have been created to oversee station activities and report to the resident manager. These general managers receive the described reports and have been tasked to ensure prompt corrective actions.

QA has also dispositioned and resolved other fire protection deficiencies or nonconformances identified in 1991, in addition to the previous audit findings.

The team reviewed QA audits performed between 1986 and 1994 and the corrective actions taken to resolve a sample of previously identified deficiencies. The following QA findings were reviewed:

- Recommendation 832, EDG fanhouse fire protection penetration seal;
- Recommendation 725, Ventilation of paint room;
- Finding 91-14-01, Operability for non-surveilled fire damper;
- Finding FPA-88-R02, Insufficient ventilation for safe shutdown equipment; and
- Corrective Action Request 768E, Operability Criteria for smoke detector functional test.

Conclusion

Based on this review, the team concluded that appropriate measures had been taken by NYPA to track and resolve QA-identified deficiencies. NYPA has initiated LERs, where appropriate, completed evaluations, implemented modifications, and completed corrective actions described in response to Violation 50-286/91-09-03.

The team concluded that corrective actions taken have been adequately prioritized and have appropriately assessed safety impact and significance. As a result of extent of condition reviews performed during initial corrective action work, ACTS items and tasks have been assigned for tracking and future resolution of issues identified.

Based on this review, the team concluded that adequate corrective actions had been taken to resolve QA-identified deficiencies associated with fire protection. For the issues that were determined to require further action necessary for resolution, appropriate measures had been established to track them for closure. The team confirmed that commitments, made by NYPA in response to Violation 50-286/91-09-03 and as discussed under Unresolved Item 50-286/93-04-07, had been implemented. Additional discussions regarding these inspection items is provided in Section 2.2 of this report. PIP 177.1 Task 24 is closed.

that operations would have responded properly to any events that would have challenged the fire protection systems. This was considered a violation of the TS. However, the violation was not cited because the criteria for discretion specified in the NRC Enforcement Policy, Section VII.B., was met.

The team noted that the licensee had compared the 1984 Appendix R reevaluation against Generic Letter 86-10 for IP3, and concluded that the previous 1984 Appendix R analysis did not address the following two issues:

1. the vulnerability of the equipment and personnel in room or zone due to the environment created by the fire or suppression systems; and

2. the consideration of high impedance faults for all associated circuits located in the fire area of concern required to meet the separation criteria of Section III.G.2 and III.G.3 of Appendix R.

The first issue was addressed in Task 27, described in Section 2.1.23 of this report. This task required development of an exemption request to approving operator access to the instrument isolation cabinets for a postulated fire at the entryway. The team noted that such an exemption existed for this location for NYPA, as referenced in the recent NRC letter to NYPA, dated December 20, 1994. To address the second issue, the licensee had issued Task 31, which is described in Section 2.1.27 of this report.

Conclusions

Based on the above described review, NYPA appropriately addressed the Generic Letter 86-10 concerns. Therefore, PIP 177.1 Task 25 is closed.

2.1.22 PIP 177.1 Task 26 (RCIP Task #22); Request for Engineering Services Resolution

Overview

The purpose of PIP Item 177.1 Task 26 was to resolve the fire protection and Appendix R-related Requests for Engineering Services (RES) that were identified as required for start-up.

Details

During this inspection, the team noted that the licensee had reviewed all the fire protection RESs as part of the ongoing PIP task. Additionally, NYPA has replaced the RES process with the engineering work request process (EWR). The team reviewed the outstanding EWR list with the system engineer. This list contained approximately 40 items, some of which were in the process of being addressed and would be closed out prior to start-up. The team found the system engineer knowledgeable of all the open EWRs. The review of the outstanding EWRs indicated no significant issue affecting the start-up concerns.

Conclusions

Based on the above described review, the team concluded that NYPA has adequately established the control of backlogged fire protection and Appendix R-related RESs/EWRs. Therefore, the PIP Task 26 is closed.

2.1.23 PIP 177.1 Task 27 (RCIP Task #23); Cable Tunnel Entryway Exemption Request

Overview

This task was initiated to track the completion of an exemption request to approve operator access to instrument isolation cabinets during a postulated fire at the entryway to the cable tunnels.

Details

During this inspection, the team noted that NYPA, in their letter, dated November 17, 1993, and supplemental letter, dated September 6, 1994, submitted a request for exemption from Section III.G.3 of Appendix R to 10 CFR 50. In response to this exemption request, the NRC in a letter, dated December 20, 1994, explained that the previously existing Appendix R exemption granted pertaining to the cable tunnel fire zone area, was valid and therefore, another exemption requested was not needed. The previous exemption was reviewed and granted by the NRC in their letter, dated February 2, 1984.

Conclusion

Based on the review of the above documentation, the team concluded that NYPA had adequately addressed the above issue. Therefore, PIP Task 27 is closed.

2.1.24 PIP 177.1 Task 28 (RCIP Task #24); Inspection of Control Building Internal Seals (Unresolved Item 50-286/93-24-04)

Overview

The purpose of this task was for NYPA to complete the technical evaluation associated with the flamemastic seals in the control building floor and the cable spreading room. This was also identified as Unresolved Item 50-286/93-24-04.

Details

The team reviewed the licensee's response to the task and the associated unresolved item. The licensee performed the reinspection of the flamemastic fire stops of the control building and cable spreading room floors. The results of this reinspection were documented in Evaluation Number 18 of ENG-

527, "Fire Barrier Inspections." This reinspection was conducted in two stages, each consisting of thirteen random reinspections. This reinspection was limited to the fire stops in the control building and cable spreading room floors. The licensee concluded the following:

1. Fourteen fire stops did not contain any foreign material and contained acceptable quantity of fiber.

2. Ten fire stops contained relatively insignificant foreign material (both combustible and non-combustible), with acceptable quantity of fiber.

3. One fire stop was void of both foreign material and fiber glass fill, thus creating an airspace between the transite bottom and marinite top. The penetration was a spare penetration (such that, no penetrating items passing through the opening).

4. One fire stop contained a significant piece of combustible material (a 14-inch long piece of 2-inch by 4-inch wood). This penetration did contain an acceptable quantity of fill.

The team walked down these areas and did not identify any deficiencies. The team also reviewed the packages that showed that the above discrepancies had been corrected.

Conclusions

Based on the above review, the team concluded that the licensee has taken appropriate corrective actions to satisfy the above discrepancies. Therefore, Task 28 and associated Unresolved Item 50-286/93-24-04 are closed.

2.1.25 PIP 177.1 Task 29 (RCIP Task #25); Absent Fire Barrier Wrap (LER 93-038)

Overview

This task was initiated to address resolution of fire barrier wrap missing on the amplifier box for No. 31 source range flux detector penetration area. The licensee also issued LER 93-038 documenting the missing fire barrier wrap in the penetration area.

Details

On September 30, 1993, with the unit in cold shutdown, the licensee determined that the plant was not in compliance with 10 CFR 50, Appendix R, Section III. G.2, because a fire barrier wrap was not installed or barriers were deficient for some plant specific areas. The licensee stated that the probable cause was a personnel error during the plant modification. To restore compliance, the licensee took the following corrective actions:

1. Reviewed the Appendix R modifications to assure that the modifications were performed in accordance with Appendix R requirements.

2. Reviewed in detail maintenance/repair and surveillance procedures for the installed fire barrier wrap.

3. The licensee revised Surveillance Procedure, 3PT-R102, "Fire Barrier/Radiant Energy Shield Inspection," which incorporated more stringent requirements for the inspection of fire barrier wrap configurations.

4. The licensee had replaced all the missing wrap with the exception of additional 120 feet of 1-hour fire barrier wrap on N-31 conduit 1VF/JA. This additional wrap would extend from the point where the existing fire wrap stops (approximately 20 foot into the upper electrical tunnel from the upper penetration area) to the point where the existing fire wrap continues again, such that the entire conduit runs inside the upper penetration area, and the upper electrical tunnel including the entryway is protected. At the end of this inspection, this work was in progress. The licensee stated that this work will be completed prior to start-up.

The team walked down the areas where the fire barrier was being wrapped. The team did not identify any deficiencies in this area.

Conclusions

Based on the above review, the team concluded that the licensee has taken appropriate corrective actions to eliminate the above-mentioned concerns. Therefore, the Task 29 and the associated LER 93-038 are closed.

2.1.26 PIP 177.1 Task 30 (RCIP Task #26); Appendix R Compliance Summary

Overview

This task was initiated to outline the compliance summary information contained in the 1984 reevaluation report in a style and format more friendly to technical personnel not intimately familiar with Appendix R requirements, IP3, or both. The completion of this task was not required for restart.

Details

The team reviewed portions of NYPA's "IP3 Appendix R, Section III.G & III.L Compliance Summary," IP3-ANAL-FP-01251, Revision 0, dated March 1995, and found it appropriate to address this task item. Additionally, the team reviewed portions of "Appendix R Operational Specifications," dated March 27, 1995, and Nuclear Safety Evaluation (NSE) 95-3-100 used to approve these operational specifications. These operational specifications identified actions to be taken should the systems, structures, or components become inoperable, and restricts the duration for which these components can remain inoperable while the plant is at operating conditions.

Conclusion

Based on the above review, the team concluded that the licensee has taken appropriated actions to address PIP 177.1 Task 30. Therefore, this item is closed.

2.1.27 PIP 177.1 Task 31 (RCIP Task #27); Multiple High Impedance Faults

Overview

This task was initiated as a result of the review of Generic Letter 86-10 efforts in the area of fire protection and Appendix R. After NRC Inspection 50-286/93-24, a new task, PIP Item 177.1, Task 31, was undertaken by NYPA to address the potential effects of Multiple High-Impedance Faults (MHIF) on safe shutdown capability. The concern associated with MHIF is a potential tripping of incoming supply circuit breakers, used for powering safe shutdown buses, due to multiple high impedance faults resulting from a fire.

Details

The team evaluated NYPA's resolution of this concern by reviewing selected portions of Report Number IP3-RPT-FP-01383, "Multiple High Impedance Fault Study," Revision 0. Through review of this report and discussions with NYPA staff, the team considered the assumptions and methodology, used to determine the potential susceptibility of the safe shutdown buses, to be appropriate and consistent with those accepted by the NRC in the past. The results of this study indicated that 8 of 26 buses could incur a trip of the incoming breaker due to postulated fires. To address these eight concerns, the report provided a listing of the fire areas in which the bus failed, and indicated specific loads which need to be shed via manual actions to prevent the loss of safe shutdown loads associated with the bus. The team verified that these manual actions were incorporated into ONOP-FP-1, "Plant Fires," Revision 7.

The team was concerned with the review and update of the MHIF study with future modifications to the plant. In response to this concern, NYPA instituted the following ACTS items:

- ACTS Item 5575, which will update MCM-19, "Modification Closeout," to include the IP3 MHIF study as a potential affected document when performing modification closeout;

- ACTS Item 4557, which will update FPES-4B, "Fire Protection/Appendix R Compliance Procedure (IP3)," to include the IP3 MHIF study as a potential affected document when performing an Appendix R compliance review; and

- ACTS Items 7335, which will update EES-6, "Control of Electrical Distribution System Changes," to include the IP3 MHIF study as a potential affected document when reviewing changes to the IP3 electrical distribution system.

The team considered this appropriate to address this concern.

Conclusion

The team considered the MHIF study to be thorough and well documented, with the recommended manual actions appropriately captured in the plant fire procedures. Therefore, PIP Task 31 is closed.

2.1.28 PIP 177.1 Task 32 (RCIP Task #28); Temporary Modification Review

Overview

This task was initiated to review temporary modifications installed prior to AP-13, "Temporary Modification Procedure," Revision 13. Prior to Revision 13 of AP-13, no guidance was provided to verify the impact of temporary modifications on the fire protection/Appendix R programs.

Details

For this task, approximately 73 temporary modifications were reviewed by a NYPA contractor. No temporary modifications were found that adversely affected the IP3 Appendix R compliance strategy. The team reviewed the guidance used by NYPA's contractor to evaluate the impact of the temporary modification on the Fire Protection/Appendix R Programs and considered it to be comprehensive. Additionally, the team verified that AP-13, Revisions 13 and 15, contained appropriate controls to ensure subsequently installed temporary modifications would not adversely impact the Fire Protection/Appendix R Programs. The team also reviewed the currently installed temporary modifications and identified no concerns.

Conclusion

The team considered NYPA's actions to address this PIP task to be appropriate. Therefore, PIP Task 32 is closed.

2.1.29 Conclusion - Short-Term Fire Protection/Appendix R-Related Corrective Actions

Based on the above review of NYPA's efforts to address the short-term fire protection/Appendix R-Related corrective actions, Inspector Follow-up Item 50-286/93-24-01 is closed. Unresolved Item 50-286/93-24-04, pertaining to operability determination of degraded and potentially nonconforming fire barrier penetrations seals and Unresolved Item 50-286/93-24-05, pertaining to the impact of modification on Appendix R, were also closed. Unresolved Item 50-286/93-24-03, pertaining to the verification of cable insulation ignition temperatures, remains unresolved. The compensatory fire watches, coupled with the other elements of the licensee's fire protection program, ensures that an adequate level of fire safety is provided for restart. Also, the team reviewed and found appropriate NYPA's LERs 93-29 and 93-38.

2.2 Emergency Lighting Issues

The team reviewed the adequacy of installed emergency lights required during loss of normal and backup lighting for vital plant areas and equipment. Lighting for these areas and equipment are required to achieve and maintain hot shutdown. This review was performed to verify compliance with Appendix R, Section III.J. of 10 CFR Part 50, and to verify adequate illumination to execute the alternate safe shutdown actions to be taken by plant operators.

The team performed a walkdown of all plant areas required in a blackout condition to support their assessment and verify adequate illumination to execute the alternate safe shutdown actions. The team's review also included an assessment of corrective actions taken by the licensee to address previously identified emergency lighting issues.

2.2.1 PIP 177.1 Task 18 (RCIP Task #14); Appendix R Emergency Battery Light Issues (Violation 91-09-03 and Unresolved Item 50-286/93-04-07)

Overview

The purpose of this task was to resolve emergency lighting deficiencies associated with 8-hour discharge testing, blackout testing, proper aiming, and maintenance and surveillance procedures in accordance with industry and vendor recommendations. NRC concerns related to these deficiencies were identified in several inspection reports, including Violation 50-286/91-09-03 and Unresolved Item 50-286/93-04-07.

Details

NYPA has addressed these concerns by completing a design review of the installed emergency battery lighting (EBL) units, revising procedures, and by performance of a blackout test, ENG-533, Revision 3, "Appendix R Emergency Battery Lighting Area Blackout Test." Concerns related to 8-hour discharge testing, monthly functional test procedures, and the lack of adequately installed emergency lighting in the plant turbine areas were adequately resolved and were documented in NRC Inspection Report 50-286/94-29.

To address the issues regarding the illumination acceptability of installed EBLs, mispositioning of the installed EBLs, and the lack of documentation to indicate that tests had been performed to verify light adequacy, the licensee has completed detailed EBL pathway drawings and Procedure ENG-533. ENG-533 served to verify the adequacy of Appendix R lighting utilized during an alternative shutdown fire scenario that requires evacuation of the control room. Off Normal Operating Procedure ONOP-FP-1A, Revision 8, "Safe Shutdown From Outside The Control Room," presents the necessary equipment needed by plant operators to achieve and maintain safe shutdown.

During performance of ENG-533, Revision 1, the licensee identified insufficient emergency lighting to illuminate the 6.9 kV switchgear area, turbine front standard, and three standby gas turbine substation cubicles, which required manual actions to operate safe shutdown equipment. Subsequently, the licensee submitted LERs 93-055 and 93-055-01 and corrective actions to address these deficiencies.

Actions taken by NYPA to correct these deficiencies included the development and implementation of modifications for installing EBLs in those identified areas (Design Change DC94-3-212 EML, Revision 0). The team verified the adequacy of EBLs for all plant areas, equipment, and access/egress pathways required for alternate safe shutdown as presented in ONOP-FP-1A. This verification was performed by the team during execution of the blackout test Procedure ENG-533, Revision 3. This test was performed in a blackout condition using a senior reactor operator to simulate the required alternate safe shutdown actions. The team noted that EBLs were verified under this procedure for equipment and areas needed to achieve and maintain the plant in cold shutdown. This verification was above the minimum requirements for only achieving hot shutdown. EBLs were adjusted where necessary to provide maximum illumination. Almost all EBLs had alignment markings applied for ease of future verification of proper EBL orientation. Exceptions to those EBLs marked included EBL units located in areas of high clearance that require ladders to adjust and could not be disturbed easily.

Review of licensee actions to resolve fire protection and Appendix R lighting issues included a telephone conversation held between NYPA and the NRC on December 21, 1994. During this conversation, NYPA provided their position on the use of existing security lighting in lieu of installing additional exterior 8-hour emergency lighting needed during certain Appendix R scenarios. These scenarios included operator actions to read level indication for the condensate and refueling water storage tanks, cleaning of backup service water strainers, and manually backflushing main service water strainers. The team verified that ACTS numbers and tasks had been assigned for tracking and future resolution of these issues. On March 15, 1995, the licensee formally submitted an exemption request to utilize yard area lighting in lieu of 8-hour battery-powered lights in outside areas. The Office of Nuclear Reactor Regulation issued the exemption request on March 29, 1995.

Conclusion

The team concluded that the blackout testing performed properly verified EBL aiming and illumination levels required by Appendix R to ensure necessary actions can be performed. Additionally, EBLs needed to achieve and maintain cold shutdown were also verified through performance of the blackout test. Corrective actions taken by the licensee to resolve previously identified lighting deficiencies were adequate. The team determined that actions taken by NYPA appropriately resolved NRC emergency lighting concerns associated with Violation 50-286/91-09-03 and Unresolved Item 50-286/93-04-07. Additional discussion associated with these inspection items is made in report Section 2.1.20. Based on the above review, these inspection items and PIP 177.1 Task 18 (RCIP Task #14) are closed.

2.2.2 PIP 177.1 Task 19 (RCIP Task #15); Development of Modification for Additional Emergency Lights in Turbine and Administration Buildings

Overview

The purpose of this task was to resolve emergency light deficiencies identified in LER 93-007. This LER was initiated to address two specific access pathways that were found not to have 8-hour EBLs installed. These pathways were within the turbine and administration buildings. Specifically, one pathway was for senior reactor operator (SRO) egress to the primary auxiliary building needed during evacuation of the central control room during an Appendix R scenario, and the other pathway was for shift supervisor egress from the turbine building 53-foot elevation to the 15-foot level via the turbine building middle stairway. This route was required for access to alternate safe shutdown equipment located on the 15-foot level of the turbine building.

Details

Corrective actions initiated by NYPA in response to this identification included development and implementation of minor modification 93-3-253EML, Revision 0, "Emergency Battery Light Coverages in the Turbine and Administration Building." In addition, the licensee created a fire protection system engineer position at Indian Point 3, responsible for monitoring and assessing fire protection and Appendix R compliance issues, and semi-annual maintenance Procedure ELC-018-GEN, Revision 4, "Inspection, Replacement and Semi-Annual Operability Testing of Appendix R Lighting Units," for periodic verification of EBL adequacy. Furthermore, the adequacy of EBL aiming and illumination was verified by the team during performance of ENG-533, as discussed in report Section 2.2.1.

Conclusion

Based on NYPA's actions to install the 8-hour EBLs and establish measures to verify, inspect, and maintain EBLs, the team concluded that the concerns associated with this task had been adequately resolved. Also, the team verified the acceptance of these EBLs during performance of ENG-533. Based on this review, PIP 177.1 Task 19 (RCIP Task No. 15) is closed.

2.3 PIP 177.1 Tasks 7 AND 8 (RCIP Tasks #3 & 4); Fire Wrap/Penetration Related Issues (Unresolved Items 50-286/93-08-07 & 50-286/93-24-06)

Overview

The stated purpose of PIP Item 177.1 Task 7 and the associated Unresolved Item 50-286/93-24-06 was to walkdown the HEMYC wrap installed throughout the plant and credited for 10 CFR 50, Appendix R, compliance to: (1) define the purpose of the wrap; (2) detail improvements and changes needed; and (3) revise the identified procedures for the repair and surveillance of the HEMYC wrap. The purpose of Task 8 was to walk down the marinite board currently installed inside containment and credited for 10 CFR 50, Appendix R, compliance to: (1) define the board placement and purpose; (2) detail improvements and changes

needed; and (3) identify and revise the procedures for the repair and surveillance of the Appendix R-credited marinite board. Additionally, the team reviewed Unresolved Item 50-286/93-08-07, pertaining to the adequacy of NYPA's surveillance program to identify seal penetration deficiencies.

2.3.1 Fire Barrier Inside Containment

Details

During this inspection, the team reviewed engineering procedure ENG-534, dated August 31, 1993, "Fire Barrier Wrap and Radiant Shields Inspections." This procedure established the definitions and functional integrity of fire barrier wraps and radiant energy shields used to establish compliance with the requirements 10 CFR Part 50, Appendix R. The functional integrity of fire barrier wraps and radiant energy shield materials including HEMYC wrap was defined in this procedure to demonstrate the ability to perform its intended function. The licensee has used HEMYC wrap and marinite board inside containment to separate redundant safe shutdown cabling and equipment. Marinite board was an acceptable material for use as per the guidance provided in GL 86-10, as a radiant energy shield inside containment.

The team determined that the specific application of HEMYC wrap inside containment provided an acceptable level of protection against the anticipated hazards of a localized fire. Therefore, the use of HEMYC wrap was determined to be an acceptable radiant energy heat shield for the specific installed applications observed by the team.

The team visually inspected several radiant energy heat shields, installed by the licensee, containing HEMYC wrap and marinite board inside containment. The team did not observe any unacceptable conditions. The licensee also has established installation/repair and surveillance procedures for HEMYC wrap and marinite board. The team reviewed these procedures and did not identify any discrepancies in these procedures.

With respect to marinite boards, the team also investigated a concern regarding missing and damaged marinite boards that were identified following the 1989 outage. The boards in question were mostly installed to satisfy FSAR cable separation requirements, while others were installed to satisfy 10 CFR 50, Appendix R requirements. The NYPA management team, in place at that time, made a decision only to replace some of the boards at that time. A safety evaluation to support this decision was apparently not completed. Based on this inspection and previous NRC and NYPA inspections of the issue in 1991, the remaining missing and damaged boards were verified to have been replaced. The team understands that NYPA is currently in the process of determining how much, if any, of the missing or damaged boards were Appendix R-related.

Based on the team's review of the above procedure, walkdown of selected penetration seals, and review of LERs 93-18 and 93-41 performed and documented in Inspection Report 94-09, Unresolved Item 50-286/93-08-07 is closed.

Conclusions

The team concluded that the licensee has adequately addressed Unresolved Item 50-286/93-08-07.

2.3.2 Fire Barrier Wrap Outside Containment

Overview

Appendix R to 10 CFR Part 50, Sections III.G.2.a, b, and c specify fire protection methods to separate redundant safe shutdown equipment and associated nonsafety-related circuits. Section III.G.2.c allows enclosure of cable and equipment and associated nonsafety-related circuits of one redundant train in a fire barrier qualified to a 1-hour fire rating when fire detectors and an automatic suppression system has been installed. Outside containment, the licensee used HEMYC wrap to meet these 1-hour separation requirements at Indian Point 3 Nuclear Station. During the 50-286/93-24 inspection, the team identified Unresolved Item 50-286/93-24-06, concerning the use of fire barrier HEMYC wrap outside containment, based on the lack of acceptable American Society for Testing of Materials (ASTM) E-119 1-hour fire tests representative of the installed plant configuration.

Details

During this inspection, the licensee provided the team with engineering evaluations of the two fire tests to support the design and installation of HEMYC fire barrier wrap for compliance with Appendix R, 1-hour separation criteria (III.G.2.c). The team reviewed the engineering evaluation for the use of HEMYC wrap in various areas of the plant outside of containment. The differences between the tested and plant configurations were judged by NYPA to have no safety significance within this evaluation. Further, the licensee has provided automatic fire detection systems, which provide area-wide coverage and an automatic suppression and detection system covering all of the cables located in trays throughout the area. The team did not identify any concerns regarding this evaluation.

Conclusions

Based on this evaluation, the team concluded that the unresolved item was closed. However, the use of all fire barrier wrapping materials are being evaluated on a generic basis for its acceptance by the NRR staff. Therefore, the staff will follow-up on the use of this material, following NRR's completed review, during a future inspection if necessary.

2.3.3 Conclusion - PIP 177.1 Tasks 7 and 8; Fire Wrap/Penetration Related Issues

The team concluded that the licensee has adequately addressed PIP 177.1 Tasks 7 and 8, and Unresolved Items 50-286/93-08-07 and 50-286/93-24-06. Therefore, these issues are closed.

2.4 Reactor Coolant Pump Oil Collection System

Overview

The team reviewed the adequacy of the design, installation, and maintenance of the oil collection system (OCS) for each of the four reactor coolant pumps (RCPs) for compliance with Section III.O to Appendix R of 10 CFR 50. This assessment included walkdowns of the installed OCS and review of the as-built drawings, design change documentation for system installation, seismic analysis, and license conditions related to the OCS.

Details

Appendix R to 10 CFR Part 50 requires such collection systems to be capable of collecting lube oil from all potential pressurized and unpressurized leak sites in the RCP lube oil systems. Leakage shall be collected and drained to a vented closed container that can hold the entire lube oil inventory. A flame arrester is required in the vent if the flash point characteristics of the oil presents the hazard of fire flashback. Leakage points to be protected shall include lift pump and piping, overflow lines, lube oil cooler, oil fill and drain lines and plugs, flanged connections on oil lines, and lube oil reservoirs where such features exist on the RCPs. The drain line shall be large enough to accommodate the largest potential oil leak.

2.4.1 Modifications

In a letter, dated March 6, 1979, the NRC issued Amendment No. 24 to the IP3 operating license. Section 3.1.12 of the Safety Evaluation Report, accompanying the license amendment, documented the requirements for the OCS. The original RCP OCS design included drip pans, enclosures, and associated piping and supports to prevent the possibility of oil making contact with the RCP components and piping and igniting. This design was purchased from Westinghouse and installed under Modification No. 80-3-083. Under the configuration and design controls in place at the time, the only documents provided for the system were the fabrication and installation drawings for the enclosures and drip pans. No drawings of the piping or piping supports were provided. The OCS is QA Category M (important to safety), but is not safety-related. It has been established to prevent an oil fire inside containment.

In a letter, dated November 16, 1981, NYPA stated that there was reasonable assurance that the OCS would remain functional during and after a safe shutdown earthquake. This assessment was based on visual examination of the system. A reanalysis of the seismic qualification of the OCS piping and associated supports was provided to the NRC in a letter, dated August 13, 1984. The results of this analysis substantiated the prior

conclusion that the OCS would not fail during a design basis event (DBE). However, NYPA stated their intentions to further enhance the seismic capability of the OCS. Seismic Calculation No. IP3-CALC-RCS-01252, Revision 0, "RCP Oil Collection Pipe Support Retrofitting," was completed for the enhancement modification to piping above elevation 65 feet, and documented the adequacy of the seismicity for the system. Based on the results of this calculation, the modification was not implemented. Based on review of the above documentation substantiating the seismic capability of the OCS, the team concluded that the design and installation of the system was acceptable to perform its intended safety function during a DBE.

The team reviewed design change DC-94-3-293, Revision 0, "RCP Oil Collection System Enclosure and Drip Pans," to evaluate the quality of the change to resolve the identified deficiencies. During this review, the team identified an engineering change notice (ECN) that did not have an engineering evaluation to support the change. ECN No. 94-3-293-001 authorized the use of a 3M epoxy gasket sealant in lieu of the originally required material, Loctite, presented on the Westinghouse installation drawings. This ECN failed to contain or reference any technical evaluation to support the product substitution. The team reviewed the procurement data for the 3M epoxy and found this epoxy to be described for uses as a pneumatic or door seal. No product data sheets were available to compare the characteristics of each epoxy. The team identified, through further discussions with engineering, that this epoxy was used for facilitating construction of the new OCS enclosures and not for use as a leak-tight sealant.

The team reviewed another ECN to DC-94-3-293 for a substitution of fastener types used to make up the joints of the drip pans and enclosures. This change was found to be supported by a technical justification/engineering evaluation. However, the team identified that other deficiencies related to ECNs have been identified. Particularly, Deviation and Event Report (DER) 94-1126, initiated from the FitzPatrick site approximately two months earlier, presented deficiencies with ECNs, including the failure to attain required reviews, incorrect drawing and ECN numbers, and missing documentation. This issue was discussed with various organizations at IP3 and it was determined that there was no means in place to ensure that information for NYPA common processes for IP3 and Fitzpatrick is shared.

The team reviewed Modification Control Manual (MCM), Procedures No. 9, Revision 5, "Engineering Change Notice," and No. 7, Revision 0, "Parts and Material Substitutions." Based on this review, the team observed that material substitutions are not prohibited from being performed under the ECN process. In addition, the team expressed concern that neither the technical evaluation nor detailed guidance provided in MCM Procedure No. 7, was presented or referenced in MCM No. 9. Based on this observation and the identification of deficiencies related to ECNs, the team considered the use of ECNs and the extent of ECNs implemented without adequate justification or evaluation, to be an unresolved issue. This issue remains unresolved pending NRC further review of the IP3 ECNs and the ECN process. The team determined that this issue was not related to start-up operations and would be reviewed during a future NRC inspection. (Unresolved Item 50-286/95-81-01)

2.4.2 Walkdowns

The team walked down each of the four RCP OCSs subsequent to the system certification, completed on November 7, 1994, and system engineer walkdowns as presented in procedure TSP-043, Revision 1. The system certification documented that the reactor coolant system, of which OCS is a part, was in acceptable working condition and available to the Operations Department. The certification also stated that additional work was required to be completed prior to declaring the system operable. The system engineer walkdown procedure presented the attributes that should be typically reviewed when conducting a walkdown. Material condition attributes listed included reference to leaking components and addressed the identification of evidence of debris in electrical enclosures. The team performed a walkdown to evaluate the installation of the OCS and to verify compliance with Appendix R.

The oil collection system for each RCP included a series of collection pans that were strategically placed to collect oil at postulated leakage points, which drained into 2-inch stainless steel piping to one of four 275-gallon collection tanks. Each collection tank had a flame arrestor located on top of the tank. The RCP motors are vertical, six-pole, squirrel cage induction motors equipped with upper and lower radial bearings and a two-way thrust bearing. The oil capacities are 175 gallons for the upper oil pot and 25 gallons for the lower. The flash point of the oil was 400°F. The upper lube oil system was considered the most significant risk for the leakage of the lube oil from the RCP motors. However, the oil lift system for the upper lube oil was found to be fully enclosed in a metal shroud designed to collect oil leakage. An ionization detector capable of detecting fire in its incipient stage was found to be located above each RCP. In addition, operators monitor RCP parameters, including oil level and thrust bearing temperatures, as indicators of pump performance. These parameters have associated annunciators located in the central control room.

The team's initial walkdown of the OCS was conducted on January 31, 1995. The team identified several discrepancies that indicated that the system did not meet the design details. These deficiencies included missing bolts, gaps in OCS enclosures, misalignment of drip pans for oil collection, leaking oil, and debris found inside the high pressure oil left pump enclosure for RCP No. 31.

The licensee initiated DER 95-0183 to address the debris found and addressed the other deficiencies by expanding the work scope of open maintenance work packages. The team verified that these open work packages and the system certification did not previously address these deficiencies. (Work Request Nos. 93-10003-00, 93-00164-08, 91-32391-08, and 93-10005-00 for each of the respective RCPs Nos. 11, 12, 13, & 14.)

Following the initial walkdown, NYPA performed corrective maintenance and closed out the repair work packages. The team performed another OCS walkdown and identified additional deficiencies. Enclosures required to be leaktight and designed to collect oil from flanges located between the RCP and upper lube oil cooler were found to have gasket material missing and gaps where some enclosures were fitted together. The licensee initiated another DER, No. 95-0283, to correct these deficiencies. The team noted that, during

Inspection 50-286/93-24, it was also observed that appropriate maintenance procedures needed to be developed for the OCS. NRC Inspection Report 50-286/93-24 also stated that licensee representatives recognized this observation and agreed to review these issues and take corrective actions, as appropriate. The team did not identify any licensee actions to address the appropriateness of maintenance procedures. However, the licensee implemented immediate corrective actions to restore the OCS to the required leak-tight design. The team concluded that the OCS for each RCP was adequately restored to fulfill Appendix R requirements. Subsequently, DER 95-0283 was closed.

The team questioned whether compliance with Appendix R had been met or maintained, considering the identified deficiencies. The licensee initiated DER No. 95-0311 to address this concern. On February 17, 1995, NYPA personnel held a critique meeting to obtain background information to address the poor material condition of the OCS and resolve DER 95-0311. The licensee determined that the root cause for the missing bolts and sealant (gasket) was the disassembly and reassembly of the OCS each time maintenance was performed on the RCP motors. In addition, the Westinghouse design drawings for the drip pans and enclosures, depicting the OCS above elevation 65 feet, were not found in the drawing system, and therefore, were not available to the maintenance department for their use in reassembling the system. In an internal letter, dated February 27, 1995, from A. Ettlinger to J. Perrotta, NYPA resolved DER 95-0311, and concluded that while the OCS did deviate from the original design, and that some of these deviations may have adversely affected its operation, the system remained and is in compliance with Appendix R. Corrective actions and associated ACTS numbers presented in this letter included the following:

- As-built drawings are being developed for all enclosures and drip pans (ACTS No. 6808);
- Maintenance procedure for disassembly/assembly of each RCP motor will be upgraded to include a formal checklist for the OCS reassembly (ACTS No. 6812); and
- A quality control inspection will be performed in lieu of a functional test of the OCS and will be included in the maintenance procedure (ACTS No. 6812).

During the inspection, the team made two additional observations. First, the team noted that a fibrous thermal barrier cloth insulation was installed in the immediate areas surrounding the RCPs. As discussed in NRC Information Notice (IN) 94-58, concerns have been identified by the NRC following a fire at Haddam Neck in 1994 regarding conditions that existed at Haddam Neck where oil that had been dispelled from the RCP, due to high velocity air currents from the RCP self cooling air and containment fans, was absorbed by the pipe insulation present in the vicinity of the RCPs. The licensee stated that ACTS Item 4178 had been issued to implement future field inspections during the next refueling outage per either a special procedure or in plant surveillance

3PT-CS-25, Revision 3, "RCP Oil Collection Tank" to verify the effectiveness of the OCS and subsequently, disposition IN 94-58. The team concluded that the licensee's assigned ACTS items to perform future field inspections of the RCPs and to evaluate the adequacy of the OCS and any oil spray patterns was appropriate.

The final observation made by the team involved the addition of oil to the RCP. The team determined that no process existed for notifying the system engineer of the quantities of oil being added by the lubrication department or operations. Therefore, trending of pump performance and amounts of oil being added cannot be adequately monitored. The licensee has assigned ACTS No. 6819 to address this issue.

The team reviewed the last two completed surveillances for determining the level in each of the four RCP oil collection tanks. Surveillance Procedure 3PT-CS-25, Revision 2, data taken on September 8, 1994, and December 9, 1994, demonstrated that the volume of oil present in each of the tanks would not affect the capability to collect the entire lube oil inventory from any RCP.

Conclusion

Based on this review of the OCS design and installation, the team concluded that the OCS was adequate to meet the requirements of 10 CFR Part 50, Section III.O. However, the team determined that management attention was needed to ensure concerns identified during this review are properly addressed. Further evaluations by the licensee were also needed to ensure the adequacy of the installed configuration for collecting oil dispelled by each RCP as described in IN 94-58. A future NRC inspection of the use and justification for supporting ECNs will be performed to address Unresolved Item 95-81-01.

2.5 Appendix R EDG

The team reviewed NYPA's response to Corrective Action Request (CAR) 828 pertaining to the adequacy of Appendix R EDG-related protective relay setpoints, and to a concern pertaining to recent reverse power trips of the Appendix R EDG due to operator error.

2.5.1 CAR 828

Overview

CAR 828 was initiated on May 23, 1993; it pertained to the adequacy of the Appendix R EDG-related protective relays. The CAR indicated that the protective relay setpoints have not been evaluated since 1985. Since that time, various modifications were implemented that could have changed the EDG loading and the required relay setpoints.

Details

NYPA performed Evaluation IP3-RPT-ED-00922, "Appendix R Diesel Generator System Evaluation," Revision 0. This evaluation included the following studies:

- Equipment Loading Analysis;
- System Voltage Drop Analysis;
- Breaker Fault Current Rating Analysis; and
- Equipment Protection and Device coordination Analysis.

Two coordination issues were identified through this evaluation; however, the impact of these issues was reviewed by the licensee and determined not to detrimentally affect the safe shutdown analysis. NYPA did initiate design document open items (DDOIs) to track the identification of these issues for possible future resolution. Additionally, future evaluations of the Appendix R EDG were planned by NYPA to enhance the protective device calibration and testing procedures, and to evaluate actual system performance. These evaluations were being tracked through ACTS Item 3669.

The team reviewed portions of Evaluation Report Number IP3-RPT-ED-00922, Revision 0. The purpose of this evaluation report was to perform a detailed system analysis calculation and evaluations to establish a sound design basis for sizing of the Appendix R diesel generator, its auxiliaries, and the associated distribution network, including the 480V MCC 312A safe shutdown equipment and protective relay setpoints. The team walked down selected components, compared the nameplate data to that used in the supporting calculations, and identified no concerns. Additionally, the team reviewed NYPA's safe shutdown determination pertaining to the coordination issues and found it to be appropriate.

The team also discussed with NYPA the root cause and corrective actions performed to ensure Appendix R-related documents are evaluated and updated during future changes to the plant. The corrective actions included the change to the electrical calculation change form, which requires the update of applicable documents associated with Appendix R EDG and associated setpoints during the modification process.

Conclusion

The team considered NYPA's action to address CAR 828 appropriate, and had no further questions regarding this issue.

2.5.2 Reverse Power Trips of the Appendix R EDG due to Operator Error

Overview

On August 23, 1993, during the performance of the Operations Department Performance Test 3PT-Q65, "Appendix R Diesel Generator Functional Test," the governor and voltage regulator switches were operated in the wrong direction, causing the generator to trip on reverse power. This incident was described in NRC Inspection Report 50-286/93-16.

Details

As documented in Inspection Report 50-286/93-16, the August 23, 1993, reverse power trip of the Appendix R EDG was the second similar trip within one year. The first trip occurred on April 23, 1993, during the performance of the test. NYPA initiated a root cause evaluation of the recurring trips and determined the cause to be the operating orientation of the two switches. Typically, the handles for these type switches are turned clockwise to raise speed or voltage. However, on the Appendix R EDG, the operator must turn the handles counter-clockwise to raise the speed or voltage. Even though the switches were appropriately labeled and the procedures provided cautions to the operation of these switches, operator errors related to these switches continued to occur. To address this concern, NYPA rewired the governor and voltage regulator switches for the Appendix R EDG to be consistent with standard industry practice. Also, the operators were informed of the switch rewiring through an Operation Shift Order, the switches were relabeled to indicate the proper configuration, and procedure cautions were removed.

The team reviewed portions of Type 1 Change 94-3-267 ARDG, "Appendix R EDG Governor & Voltage Control Switch Reversal," Revision 0, and found it appropriate. In addition, the team verified that the labels and procedures were properly updated. Discussion with the Appendix R EDG system engineer indicated that there were no subsequent testing concerns after the changes to the switches in question.

Conclusion

The team considered NYPA's actions appropriate to address the concern pertaining to the recent reverse power trips of the Appendix R EDG, due to operator error.

2.6 Fire Protection System Certification

Overview

To ensure systems were ready to exit cold shutdown conditions, IP3 systems engineers were required to perform walkdowns of their systems, and also verify the completion of open work items, or determine the acceptability to defer the work item until a later time.

Details

The team reviewed several NYPA memorandums associated with the system certification of the following systems:

- Appendix R EDG;
- Fire Protection System; and
- Emergency Battery Lighting.

The team found these memorandums identified the open work items associated with the system and provided a basis for items deferred. These memorandums were provided to all departments with the major communications between Operations Department and Technical Services. The team verified selected information from these memorandums and discussed with the licensee the controls in place to ensure all open work items required for restart would be completed and tested as needed. The team reviewed selected tests performed on various fire protection/Appendix R equipment and found them to be appropriate. The team also performed walkdowns of various fire protection/Appendix R systems and identified no concerns, with the exceptions of those in the RCP OCS described in Section 2.4.2 of this report.

Conclusion

The team concluded that the system certifications of fire protection and Appendix R-related systems provided an adequate level of assurance that the systems will be acceptable for restart.

2.7 Management Oversight

The team assessed the management oversight pertaining to the IP3 Fire Protection and Appendix R programs. The team based their assessment on discussions with various NYPA management and staff and the review of related documents. The team considered the following three areas as positive efforts:

1) The development of the Fire Protection/Appendix R Task Force. This task force was assigned the responsibility to evaluate the related open items, both NRC and NYPA-identified issues, and addressed them as needed. This task force provided concentrated resources, including the use of contracted industry specialists to act as an oversight committee to ensure adequate technical resolve for both the fire protection and Appendix R issues. Several of the NYPA-identified issues were provided to the NRC in Letter IPN-94-115, dated September 9, 1994. As documented in this letter, the resolution of issues would be complete prior to start-up. Since this letter, a number of additional potential concerns were identified by NYPA. Several of these issues and potential concerns were evaluated by the team as described in the previous sections of this report. The team also discussed the methodology used to address these issues and potential concerns with members of the task

force. The team was confident that the issues were being addressed properly. At the close of this inspection, five issues were still in the process of being resolved, but NYPA intended to complete the resolution prior to start-up.

However, NYPA is still in the process of evaluating the cumulative impact of the issues (see their 4-hour event notification of March 20, 1995). This notification requires the completion of a LER, in which NYPA intends to include the evaluation of the cumulative impact of the issues. Since the team verified the appropriate completion of the resolution to several of the issues, and the team had confidence in NYPA to appropriately address these issues and potential concerns, the NRC will evaluate the cumulative impact of these issues after the completion of the LER. This is not a restart issue.

2) The development of the Fire Protection and Safety General Supervisor position in October 1994 provided experienced supervision for the fire protection system engineer, fire protection supervisor, and the fire protection technicians. This was considered a good initiative, providing needed planning, scheduling, and additional management oversight to the fire protection program.

3) The addition of personnel with fire protection and Appendix R responsibilities to site engineering staff.

The team also noted ACTS Item 6292, requiring the development of a fire protection self-assessment program, and an implementation plan to train the staff, to be a good initiative.

2.8 Conclusion - Fire Protection/Appendix R Restart Issues

Based on the above described review, the team considered NYPA's actions appropriate to close RAP Item II.3 pertaining to fire protection and Appendix R programs, with the compensatory fire watches for the penetration seals in place until the completion of their evaluation of the cable ignition temperatures associated with Unresolved Item 50-286/93-24-03. NYPA's commitment to maintain these fire watches was confirmed during a May 10, 1995, telephone conversation between Mr. W. Ruland of Region I, and Mr. L. Hill, Indian Point 3 Resident Manager. Additionally, during this conversation, Mr. Ruland confirmed NYPA's commitment to complete all Fire Protection/Appendix R-related startup labeled ACTS items and work requests prior to plant restart.

Overall, the team considered NYPA's efforts to improve and gain control of the Fire Protection/Appendix R Programs to be effective. The majority of work items reviewed were found to be extensive and well thought-out. The team did identify a few discrepancies; however, these discrepancies did not detract from the overall good performance.

3.0 OUTSTANDING EDSFI-RELATED ISSUES (92903)

The two remaining EDSFI-related issues, Unresolved Item 50-286/91-80-10 pertaining to the EDG transient loading, and Unresolved Item 50-286/93-18-02 pertaining to EDG kW meters and associated tolerances, were reviewed. The RAP Item II.19 is associated with the outstanding EDSFI issues.

3.1 (Update) EDG Transient Loading (Unresolved Item 50-286/91-80-10)

Overview

During the EDSFI, the inspectors identified three potential concerns pertaining to the EDG transient loading capabilities. These potential concerns included: (1) the load sequencer timer tolerance acceptance criteria; (2) the recording of the EDG critical parameters; and (3) the capability of the EDGs to accelerate and load the required safety-related equipment during an accident condition.

Subsequent to the EDSFI, this issue was updated in Inspection Report 50-286/94-25, and subtasks (1) and (2) described above were reviewed and determined acceptable. Additionally, in Inspection Report 50-286.94-25, the inspector reviewed an IP3 EDG transient loading study (PTI Report IR7-93); however, the validation of the model was not complete at this time.

Details

During this inspection, the team reviewed the results of NYPA's work related to the EDG transient loading capabilities, including the following documents:

- Report No. 9780.01, "Evaluation of the Emergency Diesel Generator Limits for Their Transient Performance Capability to Ensure Safe Operation of Indian Point 3," Revision 1;
- Calculation No. IP3-CALC-480V-01412, "Evaluation of Motor Starting on Emergency Diesel Generator," Revision 0;
- NSE IP3-NSE-94-3-387, "480V Emergency Diesel Generator Units Transient Loading Capability to Start, Accelerate, and Support Safeguard Loads Sequenced During a LOCA Condition Coincident with Loss of Offsite Power," Revision 0; and
- NYPA Memorandum IP-DEE-95-58, "SI Blackout Test; Emergency Diesel Generator Transient Performance," dated March 24, 1995.

Report No. 9780.01 was completed after PTI Report No. R7-93, and incorporated the results of individual motor starting, with the exception of the containment spray pump and generator excitation system field test. In addition to the manufacturer supplied data initially used, the use of field test data allowed for the validation of the generator and the motor models. However, the diesel model still required validation. The validation of the diesel model will be described later in this section. Report No. 9780.01 contained the results of the computer simulation for all the safety-related

EDGs transient loading capabilities for various scenarios. The EDGs frequency remained above 95% rated frequency and 75% rated voltage at the motor terminal with few exceptions. The exceptions identified were determined to be acceptable in Calculation No. IP3-CALC-480V-01412; the team determined this calculation used appropriate assumptions and standard industry methodology. Additionally, the team found no concerns with the results that the identified equipment was still capable of starting with reduced voltages at the motor terminals.

The results of Report 9780.01 and Calculation IP3-CALC-480V-01412 were documented in NSE IP3-NSE-94-3-387. This NSE also documented that the overall model verification, including that of the diesels, will be performed based on the results of the safety injection (SI) Blackout Test. Correlation of discrete points between the SI-blackout test and a computer simulation of a similar scenario within ±3% of predicted voltage, and ±2% of predicted frequency would be considered acceptable for confirmation of the accuracy of the worst-case scenario. Subsequently, NYPA will complete a simulation utilizing the final model and document the result in a NSE to be issued within 60 days after the completion of the SI Blackout Test, as tracked by ACTS Item 1943. This upcoming simulation is to include a field test of the containment spray pump (CSP) and SI pump motors. The CSP motor field test data was needed because no earlier testing was performed, and the SI pump motor was being retested to verify that recent work on the SI pump did not alter the motor model.

The SI Blackout Test was performed on March 12, 1995; this test was observed by the resident inspector and documented in Inspection Report 50-286/95-02. The team discussed the results of this test with the licensee and reviewed Memorandum IP-DEE-95-58. As documented in the memorandum, the comparison between the SI Blackout Test results and the computer simulation indicated only two deviations from the acceptance criteria identified in the NSE. In both deviations, the test values showed better performance than the simulation and, therefore, NYPA considered these results acceptable. This memorandum also identified the following two observations as a result of the SI Blackout Tests:

1. Three auto sequencer timer actuations during the SI Blackout Test were outside their "as left" tolerances. Containment recirculation fan (CRF) 34 and residual heat removal pump (RHRP) 32 timers were marginally outside the allowable zone; however, auxiliary feeder water pump (AFWP) 31 was significantly outside the allowable tolerance.

2. The EDG output voltages under steady-state conditions were lower than 480V, indicating that the voltage regulator setpoints were below 480V. EDGs 31, 32, and 33 were found to be 470V, 475V, and 472V, respectively. These EDG voltages, lower than 480V, will be considered in the final evaluation of the "worst-case" diesel loading for the final safety evaluation.

The team discussed these two observations with NYPA, and the team was informed that the timers found out of specification were replaced and calibrated. With respect to the EDG voltage, NYPA has reviewed the methodology for setting the voltage regulator, which is performed monthly as part of the surveillance program, and will be accomplished at least once for each EDG between the time of the SBO test and restart of the plant. Additionally, NYPA is evaluating the feasibility of making enhancements to the methodology used in the setting of the voltage regulators.

Conclusion

Based on the above review, the team considered NYPA's EDG transient loading demonstrated a reasonable assurance that the final validation of the model and the evaluation results will be acceptable. Therefore, this issue is acceptable for restart. However, associated Unresolved Item, 50-286/91-80-10, will remain open until the completion of the final validation of the model and the software and evaluations of the worst-case scenario; it should include provisions for tolerances of the sequencer timers and the voltage regulators and the accuracy assumptions determined for the simulation. The team considered NYPA's effort pertaining to the EDG transient loading, completed to date, to be extensive. Additionally, their retesting of the SI pump motor, to verify that the recent work on the pump did not impact the motor model, was considered an example of a good questioning attitude.

3.2 (Closed) EDG kW Meter Tolerances (Unresolved Item 50-286/93-18-02)

Overview

Unresolved Item 50-286/93-18-02 pertained to the potential for the load management program to overload the EDG because the meter and associated circuitry tolerances were not considered.

Details

To address this issue, NYPA performed the following:

- Modified the electrical distribution system to minimize the loading of safety-related 480V buses;
- Revised the emergency operations procedures (EOPs) so that loading in accordance with the EOPs does not overload the EDGs; and
- Installed more accurate EDG kW meters and transducers.

The team reviewed NSE-94-3-380-ED, "Emergency Operating Procedures Revision Impact to Safeguards Bus Loading," Revision 1. The purpose of this NSE was to evaluate the impact of the latest revision to the EOPs and to ensure that they would not result in the 480V safeguard switchgear exceeding their design margin for load carry capacity.

Additionally, the impact of the EOP revision was evaluated to ensure they would not result in exceeding the EDG continuous rating of 1750 kW for more than 2 hours, or the maximum peak rating of 1950 kW. To verify the information provided in this NSE, the team reviewed selected portions of the following documents:

- Indian Point 3 Emergency Operating Procedures;
- Calculation IP3-CALC-ED-207, "480V Bus 2A, 3A, 5A, & 6A, and EDGS 31, 32 & 33 Accident Loading," Revision 4; and
- Calculation IP3-CALC-ED-01427, "Control Room EDG kW Meter Calibration and Loop Accuracy Limits," Revision 0.

The team found the calculations to be thorough, using standard industry methodology. NYPA also initiated ACTS items 6357 and 6598, associated with the recently installed kW meters. ACTS Item 6357 will track the development of a procedure to perform loop calibration on the control room EDG kW meters and transducers. ACTS Item 6598 will evaluate the operating performance of the new meter after installation to ensure the calibration frequency is adequate.

The team had discussions with both the engineering and operations staff. These discussions indicated that during the revision to the EOPs, the two departments worked together to ensure the procedures would not allow for overloading the EDGs without the use of load management. Additionally, the available loading margin for each EDG was greater than the EDG meter and loop tolerances. This should prevent the kW meters from indicating greater than the allowable kW due to inaccuracies, which would require operator action to needlessly reduce EDG loading during an accident.

Conclusion

The team determined NYPA's effort to address Unresolved Item 50-286/93-18-02 to be thorough. The team also considered the work between the operations and engineering staff to coordinate the EOPs and the loading calculation, to be an example of good interdepartment communications. Therefore, Unresolved Item 50-286/93-18-02 is closed.

3.3 Conclusion - Outstanding EDSFI Issues

Based on the team's review of Unresolved Items 50-286/91-80-10 and 50-286/93-18-02, RAP Item II.19 is closed.

4.0 INFORMATION NOTICE 93-33 (92903)

Overview

The team examined NYPA's review of NRC Information Notice (IN) 93-33, "Potential Deficiency of Certain Class 1E Instrumentation and Control Cables."

Details

IN 93-33 alerted all licensees to a potential deficiency in the environmental qualification (EQ) of certain Class 1E instrumentation and controls (I&C) cables. Specifically, the IN identified that Sandia National Laboratories (SNL), under contract to the NRC, conducted tests on cables to determine the long-term aging degradation behavior of typical I&C cables, and to determine the potential for using condition monitoring for assessing residual life.

The team examined NYPA's review of IN 93-33 as documented in their memorandum IP-TC-S-93-306 to file, dated May 14, 1993. NYPA's review was extended to all cables installed at IP3, and determined that the subject of the IN was applicable to some of the cables at IP3. NYPA concluded that the cables described in IN 93-33 were subjected to EQ testing which exceeded the required environmental parameters for IP3. The ability of the installed cables to withstand the IP3 harsh environment conditions has been demonstrated by test and was documented in the environmental qualification documentation packages for the specific cables. The team verified that the environmental qualification parameters for IP3 were less severe than the SNL test conditions. Additionally, NYPA re-evaluated IN 93-33 as part of their NRC IN pre-startup sample review program with no identified concerns.

Conclusion

The team concluded that the potential EQ concerns raised in IN 93-33 were not applicable to the installed EQ I&C cables at the IP3 facility. The team found the evaluation by the IP3 staff pertaining to this issue to be comprehensive.

5.0 MANAGEMENT MEETINGS

During the conduct of the inspection, the team met with the licensee representatives on February 10 and 17, 1995, to inform the licensee management of the scope and the findings of the inspection up to that date. Additionally, the team leader met with the licensee representative on March 24, 1995, to inform NYPA management of the remainder of the inspection findings. Subsequent to March 24, 1995, a number of telephone conversations were held between the NRC and members of NYPA's staff to discuss various topics, particularly, the concern associated with cable ignition temperatures, as described in Section 2.1.6 of this report, concluding with a telephone conversation with the Resident Manager on May 9, 1995. During this May 9, 1995, telephone conversation, NYPA's commitments to maintain fire watches, for seal penetrations until the completion of their to verify the generic information used in the Fire Seal Protection/Appendix R-related startup labeled ACTS items and work requests prior to plant startup. The licensee acknowledged the findings and did not indicate that any proprietary material was included within the scope of the inspection.

Attachment: Persons Contacted

ATTACHMENT 1

PERSONS CONTACTED

New York Power Authority

	*	M. Badorini	Sr. Staff Engineer
		A. Bartlik	Senior Fire Protection Engineer
	*	F. Bioise	Fire Protection Engineering Manager
#		W. Cahill, Jr.	Chief Nuclear Officer
		R. Casalaina	Electrical Engineer
#	*	J. Comiotes	General Manager
	* +	V. Coulehan	General Supervisor
#	* +	J. DeRoy	General Manager, Maintenance
#	* +	T. Dougherty	Vice President, Nuclear Engineering
#	* +	J. Dube	Fire Protection and Fire Safety Manager
#		N. Eggemeyer	Operations Manager
#	* +	A. Ettlinger	Director, Nuclear Engineering
#	*	C. Faison	Director, Nuclear Licensing
#		R. Finger	Acting Quality Assurance Manager
	*	J. Gagliardo	Consultant
		M. Garofalo	Sr. Quality Assurance Engineer
		T. Guarnieri	Diesel System Engineer
	*	C. Hays	Technical Manager
		J. Higgins	Systems Engineer
#	*	L. Hill	Resident Manager
	*	N. Houborgon	Maintenance Manager
		R. Johnston	Information Notice Review Group Project Manager (General Physics)
		J. Kaczor	System Engineer
#	* +	J. Kaucher	Director, Design Engineering
#	*	J. Kelly	Vice President, Regulatory Affairs
#		T. Klein	Manager of Electrical and I&C Engineering
	* +	R. Lauricella	Fire Protection Systems Engineer
	+	J. Odendahl	Instrument and Controls Manager
#	*	N. Papaije	Sr. Quality Assurance Engineer
		K. Parkinson	Fire Protection Oversight Committee Member (Sonalyists Inc.)
		F. Pellizzari	Systems Engineer
	* +	P. Peloquin	Quality Assurance Manager
#	*	K. Peters	Licensing Manager
		J. Raffaele	Electrical Engineer
		C. Reiniger	Operations Engineer
	*	L. Retier	Fire Protection Manager
		A. Russo	Electrical Engineer
	*	T. Storey	Fire Protection Oversight Committee Member (SAIC)
	* +	S. Van Buren	Fire Protection Supervisor
		D. Vinchkoski	Sr. Operations Engineer
	* +	S. Wilkie	Fire Protection Engineer
#		J. Zach	General Manager, Operations

U.S. Nuclear Regulatory Commission

*	N. Conicella	Project Manager
	C. Cowgill	Chief, Projects Branch No. 1
# * +	T. Frye	Resident Inspector
*	R. Rasmussen	Resident Inspector
*	W. Ruland	Chief, Electrical Section

* Denotes those in attendance at the February 10, 1995, meeting.

\+ Denotes those in attendance at the February 17, 1995, meeting.

\# Denotes those in attendance at the March 24, 1995, meeting.

EXHIBIT FP 9

CHAPTER 7

INSTRUMENTATION AND CONTROL

7.1 GENERAL DESIGN CRITERIA

Complete supervision of both the nuclear and turbine-generator sections of the plant is accomplished by the instrumentation and control systems from the control room. The instrumentation and control systems are designed to permit periodic on-line test to demonstrate the operability of the reactor protection system.

Criteria applying in common to all instrumentation and Control Systems are given in Section 7.1.1. Thereafter, criteria which are specific to one of the instrumentation and control systems are discussed in the appropriate portion of the description of that system, as referenced in Section 7.1.2.

The General Design Criteria presented and discussed in this section are those which were in effect at the time when Indian Point 3 was designed and constructed. These general design criteria, which formed the bases for the Indian Point 3 design, were published by the Atomic Energy Commission in the Federal Register of July 11, 1967, and subsequently made a part of 10 CFR 50.

The Authority has completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with some of the provisions of the Commission's Confirmatory Order of February 11, 1980. The detailed results of the evaluation of compliance of Indian Point 3 with the General Design Criteria presently established by the Nuclear Regulatory Commission (NRC) in 10 CFR 50 Appendix A, were submitted to NRC on August 11, 1980, and approved by the Commission on January 19, 1982. These results are presented in Section 1.3.

7.1.1 Instrumentation and Control Systems Criteria

Instrumentation and Control Systems

Criterion: Instrumentation and controls shall be provided as required to monitor and maintain within prescribed operating ranges essential reactor facility operating variables. (GDC 12 of 7/11/67)

Instrumentation and controls essential to avoid undue risk to the health and safety of the public are provided to monitor and maintain neutron flux, primary coolant pressure, flow rate, temperature, and control rod positions within prescribed operating ranges.

The non-nuclear regulating process and containment instrumentation measures temperatures, pressure, flow, and levels in the Reactor Coolant System, Steam Systems, Containment and other Auxiliary Systems.

Process variables required on a continuous basis for the startup, power operation, and shutdown of the plant are controlled form and indicated or recorded at the control room, access to which is supervised. The quantity and types of process instrumentation provided ensure safe and orderly operation of all systems and processes over the full operating range of the plant.

7.1.2 Related Criteria

The following are criteria which are related to all instrumentation and control systems but are more specific to other plant features or systems, and therefore are discussed in other chapters, as listed.

Title of Criterion (7/11/67 issue)	Reference
Suppression of Power Oscillations (GDC 7)	Chapter 3
Reactor Core Design (GDC 6)	Chapter 3
Quality Standards (GDC 1)	Chapter 4
Performance Standards (GDC 2)	Chapter 4
Fire Protection (GDC 3)	Chapter 5 and 9
Missile Protection (GDC 40)	Chapters 4, 5, and 6
Emergency Power (GDC 39 and GDC 24)	Chapter 8

7.2 PROTECTIVE SYSTEMS

The protective systems consist of both the Reactor Protection System and the Engineered Safety Features. Equipment supplying signals to any of these protective systems is considered a part of that protective system.

7.2.1 Design Bases

The General Design Criteria presented and discussed in this section are those which were in effect at the time when Indian Point 3 was designed and constructed. These general design criteria, which formed the bases for the Indian Point 3 design, were published by the Atomic Energy Commission in the Federal Register of July 11, 1967, and subsequently, made a part of 10 CFR 50.

The Authority has completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with some of the provisions of the Commission's Confirmatory Order of February 11, 1980. The detailed results of the evaluation of compliance of Indian Point 3 with the General Design Criteria presently established by the Nuclear Regulatory Commission (NCR) in 10 CFR 50 Appendix A, were submitted to NRC on August 11, 1980 and approved by the Commission on January 19, 1982. These results are presented in Section 1.3.

Control Room

Criterion: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposure of personnel. (GDC 11 of 7/11/67)

Indian Point 3 is equipped with a Control Room which contains those controls and instrumentation necessary for operation of the reactor and turbine generator under normal and accident conditions.

The Control Room is provided with emergency lighting; color coding, labeling and demarcation of reactor coolant control and display panels; switch protection; and other aids as required to ensure proper operation of the reactor, turbine generator and auxiliaries under all operating and accident conditions.

The Control Room is continuously occupied by qualified operating personnel under all operating and Maximum Credible Accident (MCA) conditions. The Post Accident Monitoring instrumentation available to the operator for monitoring plant conditions is provided in Table 7.5-1. The instrumentation complies with Regulatory Guide 1.97 requirements, as documented in NRC Letter, J.D. Neighbors to R. Beedle, dated 4/3/91, entitled "Emergency Response Capability – Conformance To RG 1.97 Revision 3, for Indian Point 3" (TAC No. 51099).

The instrumentation originally available to the operator for monitoring conditions in the Reactor, Reactor Coolant System and the Containment Building are provided in Historical Tables 7.2-4 and 7.2-5.

Historical Table 7.2-4 lists indication (meters, recorders, etc.) available for providing information following moderate and infrequent faults as originally analyzed in Chapter 14. Similarly, Historical Table 7.2-5 relates to limiting faults such as a LOCA as originally analyzed in Chapter 14.

The design criteria used in the selection of the original readouts were:

1) The range of readouts extend over the maximum expected range of the variable being measured as a result of faults originally analyzed in Chapter 14.

2) The combined indicated accuracies are within the errors originally assumed in the safety analysis.

Sufficient shielding, distance, and containment integrity are provided to assure that control room personnel shall not be subjected to doses under postulated accident conditions during occupancy of, ingress to and egress from the Control Room which, in the aggregate, would exceed that limits in 10 CFR 100. The control room ventilation consists of a system having a large percentage of recirculated air. The fresh air intake can be closed automatically or by manual backup to stop the intake of airborne activity if monitors indicate that such action is appropriate.

Core Protection Systems

Criterion: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits. (GDC 14 of 7/11/67)

The basic reactor tripping philosophy is to define a region of power and coolant temperature conditions allowed by the primary tripping functions, the overpower ΔT trip, the overtemperature ΔT trip and the nuclear overpower trip. The allowable operating region within these trip settings

is provided to prevent any combination of power, temperatures and pressure which would result in DNB with all reactor coolant pumps in operation. Additional tripping functions such as a high pressurizer pressure trip, low pressurizer pressure trip, high pressurizer water level trip, loss of flow trip, steam and feed-water flow mismatch trip, steam generator low-low water level trip, turbine trip, safety injection trip, nuclear source and intermediate range trips, and manual trip are provided as backup tot he primary tripping functions for specific accident conditions and mechanical failures.

A dropped rod signal blocks automatic rod withdrawal and also provides a turbine load cutback if above a given power level. The dropped rod is indicated from individual rod position indicators or by a rapid flux decrease on any of the power range nuclear channels.

Over power ΔT, overtemperature ΔT, and T_{avg} deviation rod stops prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by a malfunction of the Reactor Control System or by operator violation of administrative procedures.

Engineered Safety Features Protection Systems

Criterion: Protection systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features (GDC 15 of 7/11/67).

Instrumentation and controls provided for the protective systems are designed to trip the reactor in order to prevent or limit fission product release from the core, and to limit energy release, to signal containment isolation, and to control the operation of engineered safety features equipment.

The Engineered Safety Features are actuated by the engineered safety features actuation channels. Each coincidence network energizes an engineered safety features actuation device, which operates the associated engineered safety features equipment, motor starters and valve operators. The channels are designed to combine redundant sensors, independent channel circuitry, coincident trip logic and different parameter measurements so that a safe and reliable system is provided in which a single failure will not defeat the protective function. The action initiating sensors, bistables and logic is shown in the figures which are included in the detailed engineered safety features instrumentation description given in the design section for each system. The engineered safety features instrumentation system actuates (depending on the severity of the condition) the Safety Injection System, the Containment Isolation System, the Containment Air Recirculation System, and the Containment Spray System.

The passive accumulators of the Safety Injection System do not require signal or power sources to perform their function. The actuation of the active portion of the Safety Injection System is described later in this section.

The containment air recirculation coolers are normally in use during plant operation. These units are, however, in the automatic sequence, which actuates the engineered safety features upon receiving the necessary actuating signals indicating an accident condition. The fan cooler bypass valves open on a safety injection signal to provide maximum service water flow.

Containment spray is actuated by coincident and redundant high containment pressure signals (high-high level).

The Containment Isolation System provides the means of isolating the various pipes passing through the containment walls as required to prevent the release of radioactivity to the outside environment in the event of a Loss-of-Coolant Accident.

Protection Systems Reliability

Criterion: Protection systems shall be designed for high functional reliability and in-service testability necessary to avoid undue risk to the health and safety of the public. (GDC 10 of 7/11/67)

The reactor uses the high speed version of the Westinghouse magnetic-type control rod drive mechanisms. Upon a loss of power to the coils, the Rod Cluster Control (RCC) assemblies with full length absorber rods are released and fall by gravity into the core.

The reactor internals, fuel assemblies and drive system components were designed as seismic Class I equipment. The RCC assemblies are fully guided through the fuel assembly and for the maximum travel of the control rod into the guide tube. Furthermore, the RCC assemblies are never fully withdrawn from their guide thimbles in the fuel assembly. For this reason, and because of the flexibility designed into the RCC assemblies, abnormal loadings and misalignments can be sustained without impairing operation of the RCC assemblies.

The Rod Cluster Control assembly guide system is locked together with pins throughout its length to ensure against misalignments which might impair control rod movement under normal operating conditions and credible accident conditions. An analogous system has successfully undergone 4132 hours of testing in the Westinghouse Reactor Evaluation Center during which about 27,200 feet of step-driven travel and 1461 trips were accomplished with test misalignments in excess of the maximum possible misalignment experienced when installed in the plant.

All primary reactor trip protection channels required during power operation are supplied with sufficient redundancy to provide the capability for channel calibration and test at power.

Removal of one trip circuit is accomplished by placing that circuit in a tripped mode i.e., a two-out-of-three circuit becomes a one-out-of-two circuit. A Channel bistable may also be placed in a bypassed mode, i.e., a two-out-of-three circuit becomes a two-out-of-two circuit. Testing in a bypassed mode does not trip the system even if a trip condition exists in a concurrent channel.

Reliability and independence are obtained by redundancy within each tripping function. In a two-out-of-three circuit, for example, the three channels are equipped with separate primary sensors. Each channel is continuously fed from its own independent electrical source. Failure to de-energize a channel when required would be a mode of malfunction that would affect only that channel. The trip signal furnished by the two remaining channels would be unimpaired in this event.

Protection Systems Redundancy and Independence

Criterion: Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure on removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection function to be served. (GDC 20 of 7/11/67)

The Reactor Protection Systems were designed so that the most probable modes of failure (loss of voltage, relay failure) in each protection channel result in a signal calling for the protective trip. Each protection system design combines redundant sensors and channel independence with coincident trip philosophy so that a safe and reliable system is provided in which a single failure will not defeat the channel function, cause a spurious plant trip, or violate reactor protection criteria.

The design basis for the Reactor Protection System and Engineered Safety Features equipment radiation exposure was that the equipment must function after the exposure associated with the TID-14844 model accident. The maximum anticipated exposure for components located within the Containment was calculated to be 1.6×10^8 rads, which is accumulated during one year following the accident. (Note that the integrated exposure for safeguards equipment during 40 years of operation was calculated to be less than 5×10^5 rads.) In the determination of exposure, no credit was taken for containment cleanup or other removal mechanism other than isotope decay. The expected integrated exposure on the outside of the Containment Building, again assuming TID-14844 releases and no credit for cleanup, will be less than 10^2 rads integrated over a year at the containment outside surface.

Protection system instrument cables are divided into four channels. Channeling separation is continuous from instrument sensor to receiver. Bistable or digital type outputs 120 volts AC or 125 volts DC to protection system logic relays are divided into the same four channels.

Power and control cables for engineered safeguards are divided into three basic channel systems. Power and control cabling for reactor trip and containment isolation valves are divided into two channels.

In addition to channels of separation, cables were assigned to individual routing systems in accordance with their voltage level, size, and function. Six independent conduit and tray systems are employed on Indian Point 3 as follows:

1) 6900 volt power

2) Heavy 125 volts DC power cables and heavy 480 volts AC (over 100 hp) power cables

3) Lighting panel feeders and medium power (greater than No 12 AWG wire size) 480 volts AC cables

4) Control and light (non-heavy) power cables

5) Instrument cables

6) Rod control cables

Conduit fill for all systems is based on standard national Electric Code Recommendations. Criteria for tray fill are given in Section 8.2

Cables in the conduit and cable schedule are identified by a circuit code, in addition to their routing, to assure that the cable will be installed in the proper tray systems, as well as the proper channel.

Separation of channels was established throughout the plant by the use of separate trays or conduits (exceptions are documented and justified in Reference 1). In addition, whenever a heavy power tray was located less than three feet beneath any tray of a different channel, a transit fire barrier was installed between the trays. A vertical barrier was installed where trays of different channels were installed less than one foot apart, horizontally. Vertically barriers and fire wraps were installed to separate cables and equipment and associated non-safety circuits of redundant trains to protect against radiant energy from a 10 CFR 50, Appendix R assumed fire. Additionally, a horizontal barrier was installed where trays (other than heavy power) were installed less than one foot beneath any tray of a different channel.

In the area of the electrical tunnel between the Control Building and Containment Building and containment penetration area, two tunnels provide the separation for the four channels. A cross section of this portion of the tunnel is shown in the Plant Drawing 9321-F-31193 [Formerly Figure 7.2-18].

In general, control board switches with their associated indicating lights are contained in a modularized structure which provides physical separation between power "trains." Where more than one train is required to connect to a single switch, the wiring is routed to different quadrants within the module itself. Separate connectors for each redundant circuit are used, and board wiring is channelized to separate terminal blocks contained in individual channelized vertical risers located above separated floor slots. The wiring "trains" within the board are divided into three separate groups. Train "X" is that wiring which is associated with buses fed from diesel generator No. 32, Train "Y" is that wiring which is associated with buses fed from diesel generator No. 33 and Train "Z" is that wiring which is associated with buses fed from diesel generator No. 31. These "trains" are physically separated from each other by horizontal raceways which route the wiring to its appropriate vertical riser.

The wiring of local control panels which contain cabling from different channels have been separated by interior metal barriers or were separated into more than one panel. The main three phase power circuits are protected by means of three-pole breakers. Individual small power feeds from the motor control centers have three phase protection by means of fuses and "heater" overload devices. Single phase circuits are protected by single pole devices including fuses and/or breakers. (See Section 8.2)

Channel independence is carried throughout the system extending from the sensor to the relay actuating the protective function. The protective and control functions are fully isolated, control being derived from the primary protection signal path through an isolation amplifier. As such, a failure in the control circuitry does not affect the protection channel. This approach is used for pressurizer pressure and water level channels, steam generator water level, T_{avg} and ΔT channels, steam flow-feedwater flow and nuclear instrumentation channels.

The analog type equipment associated with the Reactor Protection and Engineered Safety Features Systems is considered to be the most susceptible to temperature effects because of the accuracies involved. Excessive temperature for long periods in areas containing switchgear, cables, etc. would result in a slight degradation of life but would not affect performance. The Control Room is the limiting case for reactor shutdown with regard to electrical equipment. The protective equipment in the control and relay rooms was designed to operate in an environment up to 120°F without loss of function.

Temperature in the Control Room and adjoining equipment room is maintained for personnel comfort at 70 ± 10°F. Protective equipment in this space was designed to operate within a design tolerance over this temperature range. Design specifications for this equipment specified no loss of protective function up to 120°F. Exceptions to this are evaluated in NSE 95-3-032, Revision 1 (See FSAR Section 9.9.2). Thus, there is a wide margin between design limits and the normal operating environment for control room equipment.

The engineered safety features equipment is actuated by one or the other of the engineered safety features actuation channels. Each coincidence network actuates an engineered safety actuation device that operates the associated engineered safety features equipment, motor starters and valve operators. As an example, the control circuit of a safety injection pump is typical of the control circuit for a large pump operated from switchgear. The actuation relay, energized by the Engineered Safety Features Instrumentation System, has normally open contracts. These contacts energize the circuit breaker closing coil to start the pump when the control relay is energized. The Engineered Safety Features Instrumentation System actuates (depending on the severity of the condition) the Safety Injection System, the Containment Isolation System, Containment Air Recirculation System and Containment Spray System.

In the Reactor Protection System, two reactor trip breakers are provided to interrupt power to the full length rod drive mechanisms. The breaker main contacts are connected in series (with power supply) so that opening either reactor trip breaker interrupts power to all full length rod mechanisms, permitting them to fall by gravity into the core.

In the event of a loss of reactor trip breaker control power, the reactor trip breaker under voltage coils and associated relays are de-energized and the breakers trip to an open mode. An electrical interlock prevents both bypass breakers from being closed concurrently.

Further detail on redundancy is provided through the detailed descriptions of the respective systems covered by the various sections in this chapter. In summary, reactor protection was designed to meet all presently defined reactor protection criteria and is in accordance with the IEEE-279-1971, "Standard for Nuclear Plant Protection Systems."

Required continuous electrical supply is discussed in Chapter 8.

Demonstration of Functional Operability of Protection Systems

Criterion: Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred. (GDC 25 of 7/11/67)

The analog equipment of each protection channel in service at power is capable of being tested and tripped independently by simulated analog input signals to verify its operation. The trip logic circuitry includes means to test each logic channel through to the trip breakers. Thus, the operability of each trip channel can be determined conveniently and without ambiguity.

Testing of the diesel-generator starting may be performed from the diesel generator control board. The generator breaker is not closed automatically after starting during this testing. The generator may be manually synchronized to the 480 Volt bus for loading. Complete testing of the starting of diesel generators can be accomplished by tripping the associated 480 Volt undervoltage relays and providing a coincident simulated safeguards signal. The ability of the

units to start within the prescribed time and to carry load can be periodically checked. (The Electrical Systems are discussed in more detail in Section 8.2.3.)

The reactor coolant pump breakers open trip is not testable at power; it is a backup trip which is testable only during shutdown. Testing at power (opening the breakers) would involve a loss of flow in the associated loop.

Protection Against Multiple Disability for Protection Systems

Criterion: The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function or shall be tolerable on some basis. (GDC 23 of 7/11/67)

The components of the protection system were designed and laid out so that the mechanical and thermal environment accompanying any emergency situation in which the components are required to function does not interfere with that function.

Separation of redundant analog protection channels originates at the process sensors and continues back through the field wiring and containment penetrations to the analog protection racks. Physical separation is used to the maximum practical extent to achieve separation of redundant transmitters. Separation of field wiring is achieved using separate wire ways, cable trays, conduit runs and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating redundant components in different protection racks. Each redundant channel is energized from a different vital instrument bus.

Protection System Failure Analysis Design

Criterion: The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced. (GDC 26 of 7/11/67)

Each reactor trip circuit was designed so that trip occurs when the circuit is de-energized; therefore, loss of channel power causes the system to go into its trip mode. In a two-out-of-three circuit, the three channels are equipped with separate primary sensors and each channel is energized from an independent electrical bus. Failure to de-energize when required is a mode of malfunction that affects only one channel. The trip signal furnished by the two remaining channels is unimpaired in this event.

Reactor trip is implemented by interrupting power to the magnetic latch mechanisms on all drives allowing the full length rod clusters to insert by gravity. The protection system is thus inherently safe in the event of a loss of power.

The engineered safety features actuation circuits were designed on the "energize to operate" principle unlike the reactor trip circuits.

The steam line isolation signal on high-high containment pressure, which uses the same circuitry as the containment spray actuation signal, was also designed on the "energize to operate" principle. There are a total of six high-high containment pressure instruments which

are separated into three channels. The three high-high containment pressure instrument channels are powered from three separate independent sources (one channel from instrument Bus No. 31 powered from Battery No. 31, the second channel from instrument Bus No. 33 powered from Battery No. 33, and the third channel from instrument Bus No. 34 powered from Instrument Bus No. 34 powered from Battery No. 34 with alternate supply from safeguards Motor Control Center No. 36B).

This assures operation of a sufficient number of containment pressure instruments in the event of a power failure to one of the instrument channels.

In the event that power to any instrument bus is lost, there is no single failure that could occur to prevent any protective action. Reactor trip initiation signals are de-energized to actuate. The containment spray initiation signals, of which only two of three are required, are powered from three separate power sources (i.e., Instrument Buses No. 31, No. 33, and No. 34).

If power would ever be lost to any instrument bus, channel trip annunciators, etc. associated with the protective functions powered from this bus would alarm. This would mean to the operator that this one complete protective channel is in the trip mode. The event would be indicative of the loss of power for this particular channel of protective devices.

The above design is consistent with all of the instrument buses regardless of their source of power, as the loss of any one instrument bus, for any reason, would give channel trip alarms and indications for the respective channel of protection devices. These alarms would be a true indication because on loss of instrument power the associated protective channel is indeed in the trip mode. This complies with the requirements of Section 4.20 of IEEE-279. (See Section 8.2)

Each emergency diesel-generator is started by undervoltage on its associated 480 Volt bus or by the safety injection signal independent of the other 480 Volt buses and diesel generators. Engine cranking is accomplished by a stored energy system supplied solely for the associated diesel generators. The undervoltage relay scheme was designed so that loss of 480 Volt power does not prevent the relay scheme from functioning properly.

Redundancy of Reactivity Control

Criterion: Two independent control systems, preferably of different principles, shall be n provided. (GDC 27 of 7/11/67)

One of the two Reactivity Control Systems employs rod cluster control assemblies to regulate the position of Ag-In-Cd neutron absorbers within the reactor core. The other Reactivity Control System employs the Chemical and Volume Control System to regulate the concentration of boric acid solution (neutron absorber) in the Reactor Coolant System.

A detailed description of the Reactivity Control System for Indian Point 3, sufficient to demonstrate redundancy and capability as established under the provisions of this criterion, is presented in Section 3.1.

Reactivity Control Systems Malfunction

Criterion: The reactor protection system shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous

withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits. (GDC 31 of 7/11/67)

Reactor shutdown with rods is completely independent of the normal control functions since the trip breakers completely interrupt the power to the full length rod mechanisms regardless of existing control signals. Effects of continuous withdrawal of a rod control assembly and of deboration are described in Sections 7.3.1, 7.3.2, 9.2 and 14.1.

Principles of Design

Redundancy and Independence

The protective systems are redundant and independent for all vital inputs and functions. Each channel is functionally independent of other redundant channels and is supplied from an independent power source. Isolation of redundant protection channels is described in further detail elsewhere in this section and in Section 7.2.2.

Manual Actuation

Means are provided for manual initiation of protective system action. Failures in the automatic system do not prevent the manual actuation of protective functions. Manual actuation requires the operation of a minimum of equipment.

Channel Bypass or Removal from Operation

The system was designed to permit any one channel to be maintained and when required, tested or calibrated during power operation without system trip. During such operation the active parts of the system continue to meet the single failure criterion. Since the channel under test is either tripped or superimposed, test signals are used which do not negate the process signal.

It should be noted that the "one-out-of-two" logic systems are permitted to violate the single failure criterion during channel bypass, provided that acceptable reliability of operation can be otherwise demonstrated and bypass time interval is short.

Capability for Test and Calibration

The bistable portions of the protective system (e.g., relays, bistables, etc.) provide trip signals only after signals from analog portions of the system reach preset values.

Capability is provided for calibrating and testing the performance of the bistable portion of protective channels and various combinations of the logic networks during reactor operation.

The analog portion of a protective channel provides analog signals proportional to a reactor or plant parameter. The following means are provided to permit checking the analog portion of a protective channel during reactor operation:

a) Varying the monitored variable

b) Introducing and varying a substitute transmitter signal

c) Cross checking between identical channels or between channels which bear a known relationship to each other and which have readouts available.

The design permits the administrative control of the means for manually by-passing channels or protective functions.

The design permits the administrative control of access to all trip settings, module calibration adjustments, test points, and signal injection points.

Information Readout and Indication of Bypass

The protective systems were designed to provide the operator with accurate, complete, and timely information pertinent to their own status and to plant safety.

Indication is provided in the Control Room if some part of the system has been administratively bypassed or taken out of service.

Trips are indicated and identified down to the channel level.

Vital Protective Functions and Functional Requirements

The Reactor Protective System monitors parameters related to safe operation and trips the reactor to protect the reactor core against fuel rod cladding damage caused by departure from nucleate boiling (DNB) and to protect against Reactor Coolant System damage caused by high system pressure. The engineered safety features instrumentation system monitors parameters to detect failure of the Reactor Coolant System and initiates containment isolation and engineered safety features operation to contain radioactive fission products.

This section covers those protective systems provided to:

a) Trip the reactor to prevent or limit fission product release from the core and to limit energy release.

b) Isolate containment and activate the Isolation Valve Seal Water System when necessary.

c) Control the operation of engineered safety features provided to mitigate the effects of accidents.

The core protective systems in conjunction with inherent plant characteristics were designed to prevent anticipated abnormal conditions from causing fuel damage exceeding limits established in Chapter 3 or Reactor Coolant System damage exceeding effects established in Chapter 4.

Completion of Protective Action

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are part of the protective system and were designed in accordance with the criteria of this section.

The protective systems were designed so that once initiated, a protective action goes to completion. Return to normal operation requires administrative action by the operator.

Multiple Trip Settings

Where it is necessary to change to a more restrictive trip setting to provide adequate protection for a particular mode of operation or set of operating conditions, the design provides positive means of assuring that the more restrictive trip setting is used. The devices used to prevent improper use of less restrictive trip settings are considered a part of the protective system and were designed in accordance with the other provisions of these criteria.

Interlocks and Administrative Procedures

Interlocks and administrative procedures required to limit the consequences of fault conditions other than those specified as limits for the protective function comply with the protective function comply with the protective system criteria.

Protective Actions

The Reactor Protective System automatically trips the reactor to protect the reactor core under the following conditions:

a) The reactor power, as measured by neutron flux, reaches a pre-set limit.

b) The temperature rise across the core, as determined from loop ΔT, reaches a limit either from an overpower ΔT set point or an overtemperature ΔT set point (function of T_{avg} and pressurizer pressure, adjusted by neutron flux distribution). Overtemperature ΔT set point is adjusted by neutron flux distribution.

c) The pressurizer pressure reaches an established minimum limit.

d) Loss of reactor coolant flow as sensed by low flow, loss of pump power or pump breakers opening.

e) Pressurizer pressure or level trips the reactor to protect the primary coolant boundary when the pressurizer pressure or level reaches an established maximum limit.

Interlocking functions derived from the Reactor Protective System inhibit control rod withdrawal on the occurrence of a specified parameter reaching a value lower than the value at which reactor trip is initiated.

For anticipated abnormal conditions, protective systems in conjunction with inherent plant characteristics and engineered safety features are designed to ensure that limits for energy release to the Containment and for radiation exposure (as in 10 CFR 100) are not exceeded.

Seismic Design Criteria

For either the operational or design basis earthquake, the equipment was designed to assure that it does not lose its capability to perform its function, i.e., shut the plant down and maintain it

in a safe shutdown condition. For the design basis earthquake, permanent deformation of the equipment is acceptable provided that the capability to perform its function is maintained.

7.2.2 System Design

Reactor Protective System Description

Figure 7.2-2 is a block diagram of the Reactor Protective System; Figure 7.2-3 illustrates the core thermal limits and shows the trip points that are used for the protection system. The solid lines are a locus of limiting design conditions representing the core thermal limits at five pressures. The core thermal limits are based on the conditions which yield the applicable limit value for departure from nucleate boiling ratio (DNBR) or those conditions which preclude bulk boiling at the vessel exit. The dashed lines indicate the maximum permissible trip points for the overtemperature high ΔT reactor trip including allowances for measurement and instrumentation errors.

The maximum and minimum pressures shown (2470 psia and 1750 psia) represent the set points for the high pressure and low pressure reactor trips.

Adequate margins exist between the worst steady state operating point (including all temperature, calorimetric, and pressure errors) and required trip points to preclude a spurious plant trip during design transients.

Indication

All transmitted signals (flow, pressure, temperature, etc.) which can cause a reactor trip are either indicated or recorded for every channel.

Engineered Safety Features Instrumentation Description

Plant Drawings IP3V-0171-0070, IP3V-0171-0056, 5651D72 Sheets 10, 12, and 12A [Formerly Figures 7.2-4, 7.2-5 and 7.2-6] show the action initiating sensors, bistables and logic for the engineered safety features instrumentation.

The engineered safety features actuation system automatically performs the following vital functions:

1) Start operation of the Safety Injection System upon low pressurizer pressure signal or high containment pressure signals (approximately 10% of containment design pressure), or on coincidence of high differential pressure between any two steam generators, 2 sets of 2/3 high-high pressure [energize to actuate], or after time delay (maximum 6 seconds) in coincidence with high steam flow in 2/4 lines in coincidence with (a) low T_{avg} in 2/4 lines or (b) low steam line pressure in 2/4 lines.

2) Operate the containment isolation valves in non-essential process lines upon detection of high containment pressure signals (Phase A containment isolation). The Isolation Valve Seal Water System is actuated upon automatic actuation of the Safety Injection System.

3) Start the Containment Spray System and operate the remaining containment isolation valves upon detection of a containment pressure signal higher than required in item (2) above (Phase B containment isolation; approximately 24 psig).

4) Start operation of the safeguards equipment actuation sequence signal. This includes actuating signals to such components as the Safety Injection System and the Containment Air Recirculation, Cooling and Filtration System.

Steam Line Isolation

Any of the following signals will close all steam line isolation valves:

1) After time delay (maximum 6 seconds) in coincidence with high steam flow in 2/4 lines in coincidence with (a) low T_{avg} in 2/4 lines or (b) low steam line pressure in 2/4 lines.

2) High containment pressure signals (two sets of 2/3 high-high pressure) [energize to actuate].

3) Steam line isolation valves can also be closed one at a time by manual action.

Feedwater Line Isolation

Any safety injection signal will isolate the main feedwater lines by closing all control valves (including associated MOVs) and the pump discharge valves. The closure of the pump discharge valves will cause the main feedwater pumps to trip.

ATWS Mitigating System Actuation Circuitry (AMSAC) Description

The ATWS Mitigating System Actuation Circuitry (AMSAC) is installed at IP3 in accordance with the requirements of 10 CFR 50.62 "Reduction of Risk From Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants." An ATWS is an anticipated operational occurrence (such as loss of feedwater, loss of condenser vacuum, or loss of offsite power) that is accompanied by a failure of the Reactor Protection System (RPS) to shut down the reactor. The ATWS Rule requires specific improvements in the design and operation of commercial nuclear power facilities to reduce the probability of failure to shut down the reactor following anticipated transients and to mitigate the consequences of an ATWS event.

AMSAC provides an alternate means of tripping the turbine and actuating auxiliary feedwater (AFW) flow apart from the reactor protection system (RPS). The AMSAC equipment is reasonably diverse from the existing RPS equipment to minimize the potential for common cause failures. Also, AMSAC logic power supplies and logic circuitry are independent from the RPS power supplies and logic circuitry. The turbine trip and AFW flow actuation will provide adequate assurance that the reactor coolant system (RCS) would not be subject to potential damage as a result of overpressure. The pressure limit (3200 psig) corresponds to the ASME boiler and Pressure Vessel Code Level C Service Limit stress criteria. Past ATWS analyses, see WCAP-8330 for example, show there are only two ATWS transients for which the ASME Service level limit may be approached. These transients are the Complete Loss of Normal Feedwater Without Scram and the Loss of Load Without Scram.

The Complete Loss of Normal Feedwater transient can occur due to the simultaneous tripping of the main feedwater or condensate pumps or the simultaneous closing of the main feedwater control valves or main feedwater pump discharge valves.

The Loss of Load transient considered for ATWS is one in which the vacuum in the main condenser is lost, resulting in a complete loss of normal feedwater. This could occur, for example, if the circulating water pumps trip. The main turbine will then trip on high backpressure as will any turbine-driven main feedwater pump that exhausts into the main condenser.

Since, in both of the above described transients (and in only these transients) the main feedwater is completely lost, the AMSAC is designed to actuate the auxiliary feedwater flow when the complete loss of main feedwater flow is anticipated.

Short-term protection against high reactor coolant system pressures is not required until 70% of nominal power. However, in order to minimize the amount of reactor coolant system voiding during an ATWS, AMSAC operates at and above 40% of turbine power. Furthermore, the potential exists for spurious AMSAC actuations during start-up at the lower power levels. To assure the above requirements are met, AMSAC is automatically blocked at turbine loads less than 40% by the C-20 permissive. In the event of a turbine trip, both turbine power transmitter indications will drop below 40% of full scale turbine power level. A timer in the AMSAC circuitry will maintain the trip permissive (C-20) for 330 seconds to ensure that the AMSAC system is still armed. However, in the event of an ATWS below 40% of nominal load, operator action will be required to provide long-term core protection by initiating auxiliary feedwater flow.

Actuation of AMSAC will occur on low main feedwater flow as measured by the low feedwater flow transmitters. The setpoint to actuate AMSAC is approximately 21% of nominal main feedwater flow. Although 21% flow is more than ample to protect against overpressure in the event of an ATWS, instrumentation error would become unacceptably large if a substantially lower set point were used.

An AMSAC output is initiated after a predetermined time delay whenever turbine power is 40% or greater coincident with three of the four feedwater flow transmitters indicating feedwater flow of 21% or less. The time delay is determined by the highest Turbine Power Level sensed at the time the ¾ low feedwater flow is sensed. 60 second lag units maintain Turbine Power Level close to the pre-turbine trip condition, for determination of the variable time delay. The time delay varies from a maximum of 300 seconds at 40% power to 25 seconds at 100% power (in accordance with the WOG curves). The purpose of this time delay is twofold. First, this time delay allows the reactor protection system to respond initially to a low feedwater flow condition. Secondly, during this time delay, the operator is provided with an AMSAC alert annunciator in the CR. If during the AMSAC alert period the operator increases feedwater flow above 21%, AMSAC will not actuate and the timer will reset. However, once an AMSAC signal is initiated, the signal will be maintained for at least 40 seconds to ensure all required actions occur. Turbine trip, turbine power auxiliary feedwater valve actuation and steam generator isolation and sample valve closure functions are immediately actuated by AMSAC. The motor driven auxiliary feedwater pumps have a 28 second time delay built into their starting circuits. As such, the motor driven auxiliary feedwater pumps will start 28 seconds after an AMSAC signal is initiated. This time delay is in accordance with 10 CFR 50.62 (the AMSAC Rule) which requires that the AMSAC AFW initiation function is performed within 90 seconds following initiation of an AMSAC signal. The AMSAC output signal is energized to actuate, so that a loss of power to the AMSAC cabinet will not initiate an AMSAC trip.

The AMSAC Logic Diagram is shown in Plant Drawing 9321-LL-38077 [Formerly Figure 7.2-19].

Reactor Protective System Safety Features

Separation of Redundant Protection Channels

The Reactor Protection System was designed on a channelized basis to achieve separation between redundant protection channels. The channelized design, as applied to the analog as well as the logic portions of the protection system, is illustrated by Figure 7.2-1 and is discussed below. Although shown for four channel redundancy, the design is applicable to two and three channel redundancy.

Separation of redundant analog channels originates at the process sensors and continues through the field wiring and containment penetrations to the analog protection racks.

Physical separation was used to the maximum practical extent to achieve separation of redundant transmitters. Separation of field wiring was achieved using separate wireways, cable trays, conduit runs and containment penetrations for each redundant channel. Analog equipment was separated by locating redundant components in different protection racks. Each redundant protection set is energized from a separate AC power feed.

The reactor trip bistables are mounted in the protection racks and are the final operational component in an analog protection channel. Each bistable drives two logic relays ("C" & "D"). The contacts from the "C" relays are interconnected to form the required actuation logic for Trip Breaker No. 1 through DC power feed No. 1. The transition from channel identity to logic identity is made at the logic relay coil/relay contact interface. As such, there is both electrical and physical separation between the analog and the logic portions of the protection system. The above logic network is duplicated for Trip Breaker No. 2 using DC power feed No. 2 and the contacts from the "D" relays. Therefore, the two redundant reactor trip logic channels will be physically separated and electrically isolated from one another. Overall, the protection system is comprised of identifiable channels which are physically, electrically and functionally separated and isolated from one another.

Physical Separation

The physical arrangement of all elements associated with the protective system reduces the probability of a single physical event impairing the vital functions of the system.

System equipment is distributed between instrument cabinets so as to reduce the probability of damage to the total systems by some single event.

Wiring between vital elements of the system outside of equipment housing was routed and protected so as to maintain the true redundancy of the systems with respect to physical hazards. The same channel isolation and separation criteria as described for the reactor protection circuits were applied to the engineered safety features actuation circuits.

Loss Power

A loss of power in the Reactor Protective System causes the affected channel to trip. All bistables operate in a normally energized state and go to a de-energized state to initiate action. Loss of power, thus, automatically forces the bistables into the tripped state.

Availability of power to the engineered safety features instrumentation is continuously indicated. The loss of instrument power to the sensors in the engineered safety feature instrumentation starts the engineered safety features equipment associated with the affected channels, except for containment spray which requires instrument power for actuation. Steam line isolation on high-high containment pressure, which utilizes the same actuation circuitry as the containment spray actuation, also requires power to actuate. There are a total of six high-high containment pressure instruments which are separated into three instrument channels. The three high-high containment pressure instrument channels are powered form three separate, independent sources to assure operation in the event of a power failure to one of the instrument channels.

Engineered Safety Features Systems Testing

At least once per 24 months, the master relays will be operated with test input to actuate the safeguards sequences. The test will be terminated upon verification that the associated valves are properly aligned and associated pumps are started by the automatic actuation circuits. No flow is introduced into the Reactor Coolant System; verification of pump startup is by breaker position indication and visual inspection of local flow meters in the mini-flow lines, where applicable. The tests will be performed in accordance with the Technical Specification.

Process Analog Protection Channel Testing

The basic arrangement of elements comprising a representative analog protection channel is shown in Figure 7.2-7. These elements include a sensor or transmitter, power supply, bistable, bistable trip switch and proving lamp, test-operate switch, test annunciator, test signal injection jack, and test points. A portion of the logic system is also included to illustrate the overlap between the typical analog channel and the corresponding logic circuits. The analog system symbols are given in Figure 7.2-14.

Each protection rack include a test panel containing those switches, test jacks and related equipment needed to test the channels contained in the rack. An interlocked hinged cover encloses the test panel. Opening the cover or placing the test-operate switch in the "TEST" position automatically initiates an alarm. These alarms are arranged in rack "sets" to annunciate entry to more than one rack or redundant protection "sets" or channels at any time. The test panel cover is designed such that it cannot be closed (and the alarm cleared) unless the test signal plugs (described below) are removed. Closing the test panel cover mechanically returns the test switches to the "OPERATE" position.

Test procedures allow the bistable output relays of the channel under test to be placed in the tripped mode prior to proceeding with the analog channel tests. Thus, for the channel under test, the relay elements in the two-out-of-three or the two-out-of-four coincident matrices will be in the tripped mode during the entire test of the channel. This ensures that the remaining channels of the two-out-of-three or the two-out-of-four protective functions meet the single failure criterion during the entire channel test. Placing the bistable trip switch in the tripped mode de-energizes (trips) the bistable output relays and connects a proving lamp to the bistable output circuit. This permits the electrical operation of the solid-state bistable to be observed and the bistable set point relative to the channel analog signal to be verified. Test procedures also allow the bistable output relays of the channel under test to be placed in the bypassed mode

prior to proceeding with the analog channel test; i.e., a two-out-of-three circuit becomes a two-out-of-two circuit. Testing in bypass mode is depicted in Figures 7.2-20, 7.2-21, and 7.2-22. This may only be done for circuits whose hardware does not require the use of jumpers or lifted leads to be placed in the bypass mode. Upon completion of test of the analog channel, the bistable trip switches must be manually reset to their operate mode. Closing the cover of the test panel will not transfer the bistable trip switches from their tripped to their operate position.

The following circuits are equipped with trip bypass capability:

REACTOR TRIP	AUTO SAFETY INJECTION ACTUATION
Overpower Delta T	Hi Containment Pressure
Over Temperature Delta T	Steam Line Delta P
Lo Steam Generator Level	Hi Steam Flow SI
Lo-Lo Steam Generator Level	Lo Steam Line Pressure
Steam Flow > Feedwater Flow Mismatch	Lo Tavg
Pressurizer Hi Pressure	Lo Pressurizer Pressure
Pressurizer Lo Pressure	
Pressurizer Hi Level	**TURBINE TRIP**
Lo Reactor Coolant Flow	Steam Generator Hi-Hi Level
Stop Rod Withdrawal	

Analog channel tests are accomplished by simulating a process measurement signal, varying the simulated signal over the signal span and checking the correlation of bistable set points, channel readouts and other loop elements with precision portable read-out equipment. Test jacks are provided in the test panel for injection of the simulated process signal into each process analog protection channel. Test points are provided in the channel to facilitate an independent means for precision measurement and correlation of the test signal. This procedure does not require any tools nor does it involve in any way the removal or disconnection of wires in the channel under test. In general, the analog channel circuits are arranged so that the channel power supply is loaded and is providing sensing circuit power during channel test. Load capability of the channel power supply is thereby verified by the channel test.

Nuclear Instrumentation Channel Testing

Nuclear Instrumentation Channel Systems (NIS) channels are tested by superimposing the test signal on the actual detector signal being received by the channel. The output of the bistable is not placed in a tripped condition prior to testing. A valid trip signal would then be added to the existing test signal, and thereby cause channel trip at a somewhat lower percent of actual reactor power. Protection bistable operation is tested by increasing the test signal (level signal) to the bistable trip level and verifying operation at control board alarms and/or at the NIS racks.

A NIS channel which can cause a reactor trip through one-out-of-two protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. The power range channels do not require bypass of the reactor trip function for test purposes since the protection logic is two-out-of-four. The power range dropped rod function is operated from a one-out-of-four protection logic; therefore, a bypass function is provided on each of the power range channels to prevent load cutback during the dropped rod channel test. Over-riding the dropped rod circuitry from causing a spurious turbine runback due to instrument bus noise has

no impact on the utilization of the Rod Drop Bypass Switch on each Power Range Nuclear Instrument for nuclear instrument testing.

In all cases the bypass condition and the channel test condition are alarmed on the NIS drawer and at the main control board. An interlock feature between the bypass switch and channel test switch on each channel keeps the test signal from being activated until the bypass function has been inserted. Administrative control is required to ensure that only one protection channel is placed in the bypass condition at any one time. The power range reactor trips are not affected by the bypass function described above. Therefore these power range trips will be active if required. No provision was made in the channel test circuit for reducing the channel signal level below that signal being received from the NIS detector.

Logic Channel Testing

The general design features of the logic system are described below. The trip logic channels for a typical two-out-of-three and a two-out-of-four trip function are shown in Figure 7.2-8. The analog portions of these channels are shown in Figure 7.2-9. Each bistable drives two relays ("A & B" for level and "C" & "D" for pressure). Contacts from the "A" and "C" relays are arranged in a 2/3 and 2/4 trip matrix for Trip Breaker No. 1 (RTB). The above configuration is duplicated for Trip Breaker No 2 (RTA) using contacts from the "B" and "D" relays. A series configuration is used for the trip breakers since they are actuated (opened) by undervoltage coils. This approach is consistent with a de-energize-to-trip preferred failure mode. The planned logic system testing includes exercising the reactor trip breakers to demonstrate system integrity. Bypass breakers are provided for this purpose. During normal operation, these bypass breakers are open. Administrative control is used to minimize the amount of time these breakers are closed. Closure of the breaker is controlled from its respective logic test panel in the Control Room. An interlock is provided that trips both bypass breakers open if a second bypass breaker is closed. The status of the breaker is indicated in the Control Room by indicating lights.

As shown in Figure 7.2-8 the trip signal from the logic network is simultaneously applied to the main trip breaker associated with the specific logic chain as well as the Bypass Breaker associated with the alternate trip breaker. Should a valid trip signal occur while Bypass Breaker No. 1 (BYB) is bypassing Trip Breaker No. 1 (RTB), Trip Breaker No. 2 (RTA) will be opened through its associated logic train. The trip signal applied to Trip Breaker No. 2 (RTA) is simultaneously applied to bypass breaker No. 1 (BYB) thereby opening the bypass around Trip Breaker No. 1 (RTB). RTB would either be opened manually as part of the test or would be opened through its associated logic train which would be operational or tripped during a test. Two auxiliary relays are located in parallel with the undervoltage coils of the trip breaker. The output contacts (normally closed) of these relays are connected in series and initiate actuation of the shunt trip coil of both the reactor trip and the associated bypass breaker upon a reactor trip signal. The above contacts are connected to the respective breaker shunt trip coil circuit through test switches which, during the testing of the undervoltage trip device, block the undervoltage trip signal. The test switches are supervised by control room annunciation. In addition, key operated test switches are provided for each train to allow energization of breaker shunt trip coil independent of the undervoltage trip device. The two sets of test switches in conjunction permits selection of particular reactor or bypass breaker to be tested. During response time testing, the shunt trip relay is tied to a portable recorder which is used to indicate transmission of a trip signal through the logic network. Lights are also provided to indicate the status of the individual logic relays.

The following procedure illustrates the method used for testing Trip Breaker No. 1 (RTB) and its associated logic network:

a) Manually set and trip Bypass Breaker No. 1 (BYB) to verify operation.

b) Set BYB; trip Trip Breaker No. 1 (RTB).

c) Place key operated switch "Train-Auto Defeat" to test position, verify alarm and test lamp illumination.

d) Sequentially de-energize the trip relays 9A1, A2, A3) for each logic combination (1-2, 1-3, 2-3). Verify that the logic network de-energizes the UV coil on Trip Breaker No. 1 (RTB) for each logic combination. Since the neon light monitors the signal applied to the UV coil, operation of the UV coil can be determined from the neon light.

e) Repeat "D" for every logic combination in each matrix.

f) Reset Trip Breaker No. 1 (RTB).

g) Trip RTB to validate prior test results as evidenced by the neon light.

h) Reset Trip Breaker No. 1 (RTB). Trip BYB.

In order to minimize the possibility of operational errors from either the standpoint of tripping the reactor inadvertently or only partially checking all logic combinations, each logic network includes a logic channel test panel. This panel includes those switches, indicators and recorders needed to perform the logic system test. The front panel arrangement is shown in Figure 7.2-10. The test switches used to de-energize the trip bistable relays operate through interposing relays as shown in Figures 7.2-7 and 7.2-9. This approach avoids violating the separation philosophy used in the analog channel design. Thus, although test switches for redundant channels are conveniently grouped on a single panel to facilitate testing, physical and electrical isolation of redundant protection channels are maintained by the inclusion of the interposing relay which is actuated by the logic test switches.

If the logic test switches in both engineered safeguards logic trains are placed in the test mode simultaneously, the automatic safeguards actuation will be blocked for the two trains. However, a separate alarm on the main control board is provided for each safeguard train to indicate when each train is in test.

The test switches are located in separate safeguards racks and administrative control prevents the simultaneous operation of Train A and Train B test switches.

It should be noted that either one of the safeguards train, which is blocked by its test switch, can always be unblocked and actuated by the manual safety injection switch at the main control board.

Safeguards Initiating Circuitry

The safeguards actuation circuitry and hardware layout are designed to maintain circuit isolation through the bistable operated logic relays. The channelized design follow through is shown on the Figure 7.2-15 block diagram.

The orderly arrangement of equipment for the Reactor Protection System and Engineered Safety Features Actuation System helps facilitate testing and maintenance. A color code of red, white, blue and yellow is used for analog protection channels in sets I, II, III, and IV, respectively. Large identification plates with the appropriate background color are attached at the front and back surfaces of each analog rack. The protection logic cabinets, housing the Train A logic, master relays, and slave relays, are physically separated from cabinets housing Train B equipment and identified by large identification plates on the input side of the racks where protection signals from the various protection channels are received. Small electrical components have nameplates on the enclosure which houses them. All cables are numbered with identification tags. These numbers are cross-referenced with cable schedule which specifies cable routing and function. The cable trays are color coded with each of the four channels having a different color assigned.

The safeguards bistables, mounted in the analog protection racks, drive both "A" and "B" logic matrix relays. Each matrix contains its own test light and test circuitry. The "A" and "B" logic matrices operate master relays for actuating channels A and B respectively, as shown in Figure 7.2-16.

Control power for logic channels A and B, is supplied from DC distribution panel No. 31 and No. 34, respectively. These redundant actuating channels operate the various safeguards components required with the large loads sequenced as necessary.

Protection channel identity is lost in the intermixing of the relay matrix wiring. Separation of A and B logic channels is maintained by the separate logic racks.

For safety injection, manual reset of the safeguards actuation relays may be accomplished two minutes following their operation. Once reset action is taken, the master relay is reset and its operation blocked, except for manual initiation. The engineered safeguards circuitry can be unblocked by resetting the reactor trip breaker.

Hinged safety covers on the reset pushbuttons in the circuitry of the Safety Injection, Containment Spray, Containment Isolation Phase A and Phase B, and Containment Ventilation Isolation Systems require deliberate action by the operators to actuate these pushbuttons and facilitate placing adequate administrative controls on the actuation of these pushbuttons. The Containment Ventilation Isolation System cannot be placed in a bypass condition while any of the automatic safety signals is present.

Separate and independent key-lock switches, one for each SI train, are provided in series to each of the auto SI actuation relays to allow manual blocking of the Engineered Safeguards System actuation. (See Section 6.2.2)

Logic Channel Testing

Figures 7.2-16 and 7.2-17 show the basic logic test scheme. Test switches are located in associated relay racks rather than in a single test panel. The following procedure is used for testing the logic matrices:

1) Following administrative procedure, test Channel A or B, one at a time

2) Depress the test relay switch to energize the rack test relays. An alarm will sound on the main board and a light at the rack will indicate that the safeguards rack is now in test.

3) Select a matrix and depress the logic test switches. The master relay will energize and matrix test lights will indicate upon actuation of the particular matrix being tested. The slave relay test lights will verify that the master relay contact associated with a particular slave relay has functioned and will also verify the integrity of the slave relay coils.

4) Reset the master relay by depressing the master relay reset switch. Reset the test relays by depressing the test reset switch. A lamp will glow as long as the test relays are energized. If a test relay contact in a particular slave relay circuit does not return to its normal position, then the slave relay test lamps will indicate such. Test lights can be tested by depressing the lens.

Primary Power Source

The primary source of control power for the Reactor Protective System is the vital instrument buses described in Chapter 8. The source of power for the measuring elements and the actuation circuits in the engineered safety features instrumentation is also from those buses.

Protective Actions

Reactor Trip Description

The Reactor Protection System acts to shut the reactor down by means of various reactor trips which are designed to occur when a measured plant variable exceeds predetermined limits. The protection system consists of all instrumentation which monitors the process variables and initiates trip if the process variables approach safety limits. It includes, but is not limited to, sensing elements, transmitters, converters, relays, actuating devices, interlocks, alarms, signal lines, etc. The trips function to provide rapid reduction of reactivity by the insertion of full-length RCC assemblies under free fall into the reactor core. The full-length RCC assemblies must be energized to remain withdrawn from the core.

Automatic reactor trip occurs upon the loss of power to the full-length control rods. All power to the full-length control rod mechanisms are interlocked by duplicate series connected circuit breakers. The trip breakers are opened by the undervoltage coils on both breakers. The undervoltage coils, which are normally energized, become de-energized by any one of the several trip signals.

Certain reactor trip channels (low reactor coolant flow, etc.) are automatically bypassed at low power where they are not required for safety. Nuclear source range, intermediate range and power range (low setpoint) trips, which are specifically provided for protection at low power or subcritical operation, are bypassed by operator manual action after receiving a permissive signal from the next higher range of instrumentation to allow power escalation during startup.

During power operation, a sufficiently rapid shutdown capability in the form of RCC assemblies is administratively maintained through the control rod insertion limit monitors. Administrative control requires that all shutdown rods be in the fully withdrawn position during power operation.

A resume of reactor trips, including means of actuation and the coincident circuit requirements, is given in Table 7.2.1. The permissive circuits referred to (e.g., P-7) are listed in Table 7.2-2.

Manual Trip

The manual actuating devices are independent of the automatic trip circuitry and are not subject to failures which might make the automatic circuitry inoperable. Either of two manual trip devices located in the Control Room will initiate a reactor trip.

High Nuclear Flux (Power Range) Trip

This circuit trips the reactor when two of the four power range channels read above the trip setpoint. There are two independent trip settings, one high and one low setting. The high trip setting provides protection during normal power operation. The low setting, which provides protection during startup, can be manually bypassed when two out of the four power range channels read above approximately 10% power (P-10). Three out of the four channels below 10% automatically reinstates the trip protection. The high setting is always active.

High Nuclear Flux (Intermediate Range)Trip

This circuit trips the reactor when one out of the two intermediate range channels reads above the trip setpoint. This trip, which provides protection during reactor startup, can be manually bypassed if two out of four power range channels are above approximately 10% (P-10). Three out of four channels below this value automatically reinstate the trip protection. The intermediate channels (including detectors) are separate from the power range channels.

High Nuclear Flux (Source Range) Trip

This circuit trips the reactor when one of the two source range channels reads above the trip setpoint. The trip, which provides protection during reactor startup, can be manually bypassed when one of two intermediate range channels reads above the P-6 setpoint value and is automatically reinstated when both intermediate range channels decrease below this value (P-6). This trip is also bypassed by two out of four high power range signals (P-10). It can also be reinstated below P-10 by an administrative action requiring coincident manual actuation.

The trip point is set between the intermediate range lower limit of instrument sensitivity and the upper limit of the source range instrument range.

Overtemperature ΔT Trip

The purpose of this trip is to protect the core against DNB. This circuit trips the reactor on coincidence of two-out-of-the-four signals with one channel (two temperature measurement, hot and cold) per loop. The set point for this reactor trip is continuously calculated for each channel by solving equations of this form:

$$\Delta T_{trip} - \Delta T_o [K_1 - K_2 (T_{avg} - T') + K_3 (P - P') - f (\Delta I)]$$

where

ΔT_o - indicated ΔT at rated power, F

T_{avg} - reactor coolant average temperature, two measurements in each loop (T_{avg} signal is rate compensated), F

T' - indicated T_{avg} at nominal condition at rated power, F

P - pressurizer pressure, four independent measurements, psia

P' - nominal pressure at rated power, psia

K_1 - set point bias, F

K_2, K_3 - constants based on the effect of temperature and pressure on the DNB limits

f (ΔI) - a function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers with gains selected based on measured instrument response during plant startup tests.

Overpower ΔT Trip

The purpose of this trip is to protect against excessive power (fuel rod rating protection). This circuit trips the reactor on coincidence of two out of the four signals with one channel (one pair of temperature measurements) per loop.

The set point for this reactor trip is continuously calculated for each channel by solving equations of the form;

$$\Delta T_{set\ point} - \Delta T_o [K_4 - K_5 \frac{dT_{avg}}{dt} - K_6 (T_{avg} - T')]$$

where

ΔT_o - indicated ΔT at rated power, F

T_{avg} - Average temperature, F

T' - Indicated T_{avg} at nominal conditions at rated power, F

K_4 - Set point bias

K_5 - Constant

K_6 - Constant

Low Pressurizer Pressure Trip

The purpose of this circuit is to protect against excessive core steam voids which could lead to DNB. The circuit trips the reactor on coincidence of two out of the four low pressurizer pressure signals. This trip is blocked when any three of the four power range channels and two of two turbine first stage (inlet) pressure channels read below approximately 10% power (P-7).

High Pressurizer Pressure Trip

The purpose of this circuit is to limit the range of required protection from the overtemperature ΔT trip and to protect against Reactor Coolant System over-pressure. This circuit trips the reactor on coincidence of two out of the three high pressurizer pressure signals.

High Pressurizer Water Level Trip

This trip is provided as a backup to the high pressurizer pressure trip. The coincidence of two out of the three high pressurizer water level signals trips the reactor. The trip is bypassed when any three of the four power range channels and two of the two turbine first stage (inlet) pressure channels read below approximately 10% power (P-7).

Low Reactor Coolant Flow Trip

The trip protects the core form DNB following a loss of coolant flow accident. The means of actuating the loss of coolant flow accident trip are:

a) Measured low flow in the reactor coolant loop. The low flow trip signal is actuated by the coincidence of 2/3 signals of any reactor coolant loop. The loss of flow in any two loops causes a reactor trip above approximately 10% power (P-7). Above the P-8 setpoint any one loop causes a reactor trip. The sensor used for flow measurement is an elbow tap and is discussed in Chapter 4.

b) Reactor coolant pump circuit breaker open functions similarly to the low flow signal with one sensor per reactor coolant pump breaker.

c) Underfrequency on any two of the four reactor coolant pump buses will trip all four reactor coolant pumps and cause a reactor trip above approximately 10% power (P-7).

d) Undervoltage on any two of the four reactor coolant pump buses causes a direct reactor trip above approximately 10% power (P-7).

Safety Injection System (SIS) Actuation Trip

A reactor trip occurs when the Safety Injection System is actuated. The means of actuating the SIS trips are:

1) Low pressurizer pressure (two out of three). This signal may be manually blocked or unblocked during start-up and shutdown. This block is accomplished by separate switches for each of the redundant safety injection initiation circuits. The block will be automatically removed above a designated setpoint.

2) High containment pressure (two out of three) set at approximately 10% of containment design pressure.

3) High differential pressure between any two steam lines (two out of three).

4) After time delay: high steam flow in 2/4 lines (one out of two per line), in coincidence with either low T_{avg} in 2/4 lines or low steam line pressure in 2/4 lines.

5) High-high containment pressure (two sets of two-out-of-three), set at approximately 50% of containment design pressure [energize to actuate].

6) Manual.

Turbine Generator Trip

A turbine trip is sensed by two out of three signals from auto-stop oil pressure. A turbine trip is accompanied by a direct reactor trip above P-8 and a controlled short term release of steam to the condenser occurs which removes sensible heat from the Reactor Coolant System while avoiding steam generator safety valve actuation. Any reactor trip will generate a turbine trip. Further details are discussed in Chapter 10.

Steam/Feedwater Flow Mismatch Trip

This trip protects the reactor from a sudden loss of heat sink. The trip is actuated by one steam/feedwater flow mismatch in selected coincidence with one low steam generator water level in that steam generator. There are two steam/feedwater flow mismatches and two low steam generator water level signals per loop.

Low-Low Steam Generator Water Level Trip

The purpose of this trip is to protect the steam generators for the case of a sustained steam/feedwater flow mismatch. The trip is actuated on two out of the three low-low water level signals in any steam generator. A diagram of the steam generator level control and protection system is shown in Plant Drawing IP3V-0171-0355 [Formerly Figure 7.2-13].

Rod Stops

A list of rod stops is listed in Table 7.2-3. Some of these have been previously noted under permissive circuits, but are listed again for completeness.

Rod Drop Protection

Two independent systems are provided to sense a dropped rod: a rod bottom position detection system and a system which senses sudden reduction in out-of-core neutron flux. Both protection systems initiate protective action in the form of blocking automatic rod withdrawal, and also, a turbine load cutback if above a given power level. This action compensates for accessible adverse core power distributions and permits an orderly retrieval of the dropped RCC.

The primary protection for the dropped RCC accident is the rod bottom signal derived for each rod from its individual position indication system. With the position indication system, initiation of protection is independent of rod location of reactivity worth.

Backup protection is provided by use of the out-of-core power range nuclear detectors and is particularly effective for large nuclear flux reductions occurring in the region of the core adjacent to the detectors.

The rod drop detection circuit from nuclear flux consists basically of a comparison of each ion chamber signal with the same signal taken through a first order lag network. Since a dropped

RCC assembly will rapidly depress the local neutron flux, the decrease in flux will be detected by one or more of these four sensors. Such a sudden decrease in ion chamber current will be seen as a difference signal. A negative signal output greater than a preset value (approximately 10%) from any of the four power range channels will actuate the rod drop protection.

Figure 7.4-2 indicates schematically the dropped rod detection circuits and the Nuclear Protection System in general. The potential consequences of any dropped RCC without protective action are presented in Section 14.1.4.

Alarms

Any of the following conditions actuate an alarm:

a) Reactor trip (first-out annunciator)

b) Trip of any reactor trip channel

c) Significant deviation of any major control variable (pressure, T_{avg}, pressurizer water level, and steam generator water level)

d) Actuation of any permissive circuit or override. (Certain permissive are provided with indication light only on the flight panel.)

Control Group Rod Insertion Limits

The control rod insertion limit system is used in an administrative control procedure with the objective to maintain an RCCA shutdown margin.

The control group rod insertion limits, Z_{LL}, are calculated as a linear function of reactor power and reactor coolant average temperature. The equation is:

$$Z_{LL} - A\,(\Delta T)_{avg} + B\,(\overline{T_{avg}}) + C$$

where A and B are preset manually adjustable gains and C is a preset manually adjustable bias. These set points may be different for each control bank. The $(\Delta T)_{avg}$ and $(\overline{T_{avg}})$ are the average of the individual temperature differences and the coolant average temperatures, respectively, measured from the reactor coolant hot leg and cold leg.

One insertion limit monitor with two alarm set points is provided for each control bank. A description of control and shutdown rod groups is provided in Section 7.3. The low alarm alerts the operator of an approach to a reduced shutdown reactivity situation requiring boron addition by following normal procedures with the Chemical and Volume Control System (Chapter 9). Actuation of low-low alarm requires the operator to take immediate action to add boron to the system by any one of several alternate methods.

7.2.3 System Evaluation

Reactor Protection System and DNB

The following is a description of how the reactor protection system prevents DNB.

The plant variables affecting the DNB ratio are:

- Thermal power
- Coolant flow
- Coolant temperature
- Coolant pressure
- Distribution Core power (hot channel factors)

Figure 7.2-11 illustrates the core limits for which DNBR for the hottest rod is at the design limit and shows the overpower and overtemperature ΔT reactor trips locus as a function of T_{avg} and pressure.

Excessive axial offset reduces the overtemperature ΔT setpoint associated with both the block on control rod withdrawal and the reactor trip actuation. If the ΔT of any RCS loop exceeds the calculated overpower or overtemperature ΔT setpoints, permissive signals will be generated which will initiate a block on control rod withdrawal. The setpoint on these ΔT rod blocks are approximately 2° F less than the corresponding ΔT setpoints used to actuate reactor tip. This provides a margin or buffer prior to achieving operating conditions requiring a reactor trip on overpower or overtemperature. Rod block on ΔT circuitry is not redundant, whereas the ΔT reactor trips are protective grade and meet the standards of IEEE-279.

Reactor trips for a fixed high pressurizer pressure and for a fixed low pressurizer pressure are provided to limit the pressure range over which core protection depends on the variable overpower and overtemperature ΔT trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these variables. However, for all cases in which the calculated DNBR approaches the applicable DNBR limit, a reactor trip on overpower and/or overtemperature ΔT would be actuated.

The ΔT trip functions are based on the differences between measurements of the hot leg and cold leg temperatures, which are proportional to core power.

The overtemperature ΔT trip function is provided with a nuclear flux feedback to reflect a measure of axial power distribution. This will assist in preventing an adverse distribution which could lead to exceeding allowable core conditions.

Overpower Protection

In addition to the high power range nuclear flux trips, an overpower ΔT trip is provided (2 out of 4 logic) to limit the maximum overpower.

A rod stop function and turbine runback function is provided in the form:

Δ^T rod stop = Δ^T trip - B_p

B_P = set point bias (F)

The logic for the runback is one out of four.

Overtemperature Protection

A second ΔT trip (2 out of 4 logic) provides an overtemperature trip which is a function of coolant average temperature and pressurizer pressure derived as previously discussed.

A similar rod stop function is provided in the form;

Δ^T rod stop = Δ^Ttrip - ^BT

^BT = set point bias, F

The logic for the rod stop is one out of four.

In summary, in the event the difference between top and bottom detectors exceeds the desired range, automatic feedback signals are provided to reduce the overtemperature trip setpoint and to block rod withdrawal to maintain appropriate operating margins to the trip setpoint.

Interaction of Control and Protection

The design basis for the control and protection systems permits the use of a detector for both protection and control functions. Where this is done, all equipment common to both the protection and control circuits are classified as part of the protection system. Isolation amplifiers prevent a control system failure from affecting the protection system. In addition, where failure of a protection system component can cause a process excursion which requires protective action the protection system can withstand another independent failure without loss of function. Generally, this is accomplished with two-out-of-four trip logic. Also, wherever practical, provisions are included in the protection system to prevent a plant outrage because of single failure of a sensor.

Specific Control and Protection Interactions

Nuclear Flux

Four power range nuclear flux channels are provided for nuclear overpower protection. Isolated outputs from all four channels are averaged for automatic control rod regulation of power. If any channel fails in such a way as to produce a low output, that channel is incapable of proper nuclear overpower protection. In principle, the same failure would cause rod withdrawal and overpower. Two-out-of-four nuclear overpower trip logic will ensure a nuclear overpower trip if needed even with an independent failure in another channel.

In addition, the control system will respond only to rapid changes in indicated nuclear flux; slow changes or drifts are overridden by the temperature control signals. Also, a rapid decrease of any nuclear flux signal will block automatic rod withdrawal as part of the rod drop protection circuitry.

Finally, an overpower signal from any nuclear channel will block automatic rod withdrawal. The set point for this rod stop is below the reactor trip set point.

Coolant Temperature

Four T_{avg} channels are used for overtemperature-overpower protection. (See Plant Drawings IP3V-0171-0052, -0053, -0054, and -0055 [Formerly Figure 7.2-12] for single channel). Isolated output signals from all four channels are also averaged for automatic control rod regulation. In principle, a spuriously low temperature signal from one sensor could cause rod withdrawal and overtemperature. Two-out-of-four overtemperature and overpower ΔT logic will ensure a trip is needed even with an independent failure in another channel. In addition, channel deviation alarms in the control system will block automatic rod withdrawal if any temperature channel deviates significantly from the others. Automatic rod withdrawal blocks will also occur if any one of four nuclear channels indicates an overpower condition or if any one of the four temperature channels indicates an overtemperature condition. Finally, as shown in Section 14.1, the combination of trips on nuclear overpower, high pressurizer water level, and high pressurizer pressure also serve to limit an excursion for any rate of reactivity insertion.

Narrow range RCS hot leg temperature is measured for each channel through the use of three RTDs located 120° apart. The three RTD signals are averaged by a microsprocessor to produce the hot leg signal for the channel. The microprocessor has the capability to detect a failure of any of the hot leg RTDs.

Pressurizer Pressure

Four pressure channels are used for high and low pressure protection and for overpower-overtemperature protection. Three of these are also used for high pressure protection. Isolated output signals from these channels are also used for pressure control. These are discussed separately below:

1) *Pressure Control. Spray, power-operated relief valves, and heaters are controlled by* isolated output signals from the pressure protection channels:

   a) Low Pressure

      A spurious high pressure signal from one channel can cause low pressure by actuation of a pressurizer spray valve. Spray reduces pressure at a low rate, and some time is available for operator action (about three minutes at maximum spray rate) before a low pressure trip is reached. Additional redundancy is provided by the protection system to ensure underpressure protection, i.e., two-out-of-four low pressure reactor trip logic and two-out-of-three safety injection logic.

      Each pressurizer relief valve is interlocked to prevent opening on a single high pressure signal. Furthermore, the valve setpoint is at a higher pressure than the normal high pressure signal actuation pressure.

   b) High Pressure

      The pressurizer heaters are incapable of overpressurizing the Reactor Coolant System. Maximum steam generation rate with heaters is about 15,000 lbs/hr, compared with a total capacity of 1,260,000 lbs/hr for the three safety valves and total capacity of 358,000 lbs/hr of the two power-operated relief valves. Therefore, overpressure protection is not required for a pressure control failure. Two-out-of-three high pressure trip logic is therefore used.

In addition, either of the two relief valves can easily maintain pressure below the high pressure trip point. The two relief valves are controlled by independent pressure channels, one of which is independent of the pressure channel used for heater control. Finally, the rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available for operator action.

An Overpressure Protection System prevents the reactor vessel pressure from exceeding the Technical Specification limits, as described in Section 4.3.4.

c) Pressurizer Level

The presssurizer level channels are used for high level reactor trip two out of three. Isolated output signals from these channels are used for volume control, increasing or decreasing water level. A level control failure could fill or empty the pressurizer at a slow rate (on the order of half an hour or more).

2) High Level

A reactor trip on pressurizer high water level is provided to prevent rapid thermal expansions of reactor coolant fluid from filling the pressurizer; the rapid change from high rates of steam relief to water relief can be damaging to the safety valves and relief piping and pressure relief tank. However, a level control failure cannot actuate the safety valves because the high pressure reactor trip is set below the safety valve set pressures. Therefore, a control failure does not require protection system action. In addition, ample time and alarms are available for operator action.

3) Low Level

For control failures which tend to empty the pressurizer, a low level signal from either of two independent level control channels will isolate letdown, thus preventing the loss of coolant. Ample time and alarms exist for operator action.

A low pressurizer level will result for all Loss-of-Coolant Accidents except for a special class of breaks in the range of 2 to 6 inches which occur in the vapor space of the pressurizer. For this special class which does not result in low pressurizer water level, the reactor will be tripped on either low pressure or DT overtemperature as the pressure drops, and DNB will be prevented. Following reactor trip, there will be no core damage as long as the core remains covered. Sufficient time is available in accidents of this type for the operator to take manual control of makeup to assure core cooling during subsequent cold shutdown procedures.

Sufficient redundancy is provided to accommodate the loss of one level channel without jeopardizing functional capability of the reactor protection system. In the Technical Specifications, limits are set on the minimum number of operable channels and required plant status for all reactor protection instrumentation.

Steam Generator Water Level; Feedwater Flow

Before describing control and protection interaction for these channels, it is beneficial to review the protection system basis for this instrumentation.

The basic function of the reactor protection circuits associated with low steam generator water level and low feed water flow is to preserve the steam generator heat sink for removal of long term residual heat. Should a complete loss of feedwater occur with no protective action, the steam generators would boil dry and cause an overtemperature-overpressure excursion in the reactor coolant. Reactor trips on temperature, pressure, and pressurizer water level will trip the plant before there is any damage to the core or reactor coolant system. However, residual heat generated after the reactor trip would cause a pressure spike in the pressurizer that lifts the pressurizer relief valves and causes discharge of liquid reactor coolant to the Containment. Redundant auxiliary feedwater pumps are provided to prevent this. Reactor trips act before the steam generators are dry to reduce the required capacity and starting time requirements of these pumps and to minimize the thermal transient on the reactor coolant system and steam generators. Independent trip circuits are provided for each steam generator for the following reasons:

1) Should severe mechanical damage occur to the feedwater line to one steam generator, it is difficult to ensure the functional integrity of level and flow instrumentation for that unit. For instance, a major pipe break between the feedwater flow element and the steam generator would cause high flow through the flow element. The rapid depressurization of the steam generator would drastically affect the relation between downcomer water level and steam generator water inventory.

2) It is desirable to minimize thermal transient on a steam generator for credible loss of feed water accidents.

   It should be noted that controller malfunctions caused by a protection system failure affect only one steam generator. Also, they do not impair the capability of the main feedwater system under either manual control or automatic Tavg control. Hence, these failures are far from being the worst case with respect to decay heat removal with the steam generators.

   a) <u>Feedwater Flow</u>

      A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow and prevent that channel from tripping. A reactor trip on low-low water level, independent of indicated feedwater flow, will ensure a reactor trip if needed.

      In addition, the three-element feedwater controller incorporates reset on level, such that with expected gains, a rapid increase in the flow signal would cause only a 12-inch decrease in level before the controller reopened the feedwater valve. A slow increase in the feedwater signal would have no effect at all.

   b) <u>Steam Flow</u>

      A spurious low steam flow signal would have the same effect as a high feedwater signal, discussed above.

   c) <u>Level</u>

      A spurious high water level signal from the protection channel used for control will tend to close the feedwater valve. This level channel is independent of the level and flow channels used for reactor trip on low flow coincident with low level.

1) A rapid increase in the level signal will completely stop feedwater flow and actuate a reactor trip on low feedwater flow coincident with low level.

2) A slow drift in the level signal may not actuate a low feedwater signal. Since the level decrease is slow, the operator has time to respond to low level alarms. Since only one steam generator is affected, automatic protection is not mandatory and reactor trip on two out of three low-low level is acceptable.

7.2.4 Qualification Testing

Typical protection system equipment is subjected to type tests under simulated seismic acceleration to demonstrate its ability to perform its functions. Type testing is performed using conservatively large accelerations and applicable frequencies. The peak accelerations and frequencies used are checked against those derived by structural analysis of operational and design basis earthquake loadings. Typical switches and indicators for safety features components have been tested to determine their ability to withstand seismic forces without malfunction which would defeat automatic operation of the required component.

For testing there is no adequate way of knowing what combination of vertical and horizontal input motion produces the worst effects (e.g., stresses, deflections). There is a greater probability that due to the phase relationship of the two simultaneously applied input motions, the resulting combined motion produces less severe effects than when these motions are applied separately. Testing in one direction at a time is considered the best way to obtain positive proof of the equipment's capability. (The independent testing in each of the three directions is also recommended in the IEEE Guide for Seismic Qualifications of Class I Electric Equipment.) Furthermore, the uni-directional testing was performed in a conservative manner, thus providing a margin against any greater effects which may possibly result from the worst combination of simultaneous testing. These conservatisms consist of: (1) an input sine beat motion with 10 cycles per beat, (2) resonant testing at all determined and applicable natural frequencies, (3) further testing at other selected frequencies, and (4) high input acceleration values, particularly for the vertical direction.

Qualification testing was performed on various safety systems such as process instrumentation and nuclear instrumentation. This testing involved demonstrating operation of safety functions at elevated ambient temperatures to 120°F for original control room equipment.

To establish the combined effect upon protection systems of long term operation followed by exposure to accident conditions inside the containment, selected components were subjected to thermal aging followed by irradiation. In addition, components were first irradiated and then subjected to thermal aging. Results of the tests indicate that the components would perform satisfactorily following a Design Basis Accident.

Cables of the type used for Indian Point 3 were tested using the same approach as described above, i.e., irradiation, thermal aging followed by steam exposure and thermal age, and irradiation followed by steam exposure. During exposure to steam, the cables carry nominal voltage and current.

Westinghouse Topical Reports, WCAP-7817[1], WCAP-7817 Supplement 1[2], and WCAP-8234[3] provide the seismic evaluation of safety related equipment. The type tests covered by these reports are applicable to Indian Point 3.

References

1) Vogeding, E. L., "Seismic Testing of Electrical and Control Equipment," WCAP-7817, December 1971.

2) Vogeding, E. L., "Seismic Testing of Electrical and Control Equipment (WCID Process Control Equipment)," WCAP-7817 Supplement 1, December 1971.

3) "Seismic Testing and Functional Verification of By-Pass Loop Reactor Coolant RTD's," WCAP-8234 (Westinghouse Non-Proprietary Class 3), June 1974.

4) NSE 94-3-124 ED, Rev. O "Evaluation of Cable Channelization Deficiencies."

Table 7.2-1

LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF:
ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

	COINCIDENCE CIRCUITRY AND INTERLOCKS	**COMMENTS**
REACTOR TRIP		
1) Manual	½, no interlocks	
2) Overpower nuclear flux	2/4	High and low settings; manual block and automatic reset of low setting by P-10, Table 7.2-2
3) Overtemperature !T	2/4, no interlocks	
4) Overpower !T	2/4, no interlocks	
5) Low pressurizer pressure	2/4, blocked by P-7	
6) High pressurizer pressure (fixed set points)	2/3, no interlocks	
7) High pressurizer water level	2/3, blocked by P-7	
8) a. Low reactor coolant flow	2/3, per loop, blocked by P-7, P-8	
b. Reactor coolant pump breaker	1/1, per loop, blocked by P-7, P-8	Reactor coolant pump breaker is tripped on underfrequency
c. Undervoltage on reactor coolant pump bus	2/4, per loop, blocked by P-7	
d. Underfrequency on reactor coolant pump bus	2/4	Underfrequency trips all reactor coolant pumps
9) Safety injection signal (Actuation)	2/3, low pressurizer pressure (manual block permitted by 2/3 low pressurizer pressure): or 2/3 high containment pressure (high-level): or 2/3 high differential pressure between any two steam lines, or manual ½, or two sets of 2/3 hi-hi containment pressure (high-high pressure) [energize to actuate], or after delay (maximum 6 seconds) with high steam flow in 2/4 lines coincidence with (a) low T_{avg} in 2/4 lines or (b) low steam line pressure in 2/4 lines	
10) Turbine generator	2/3, blocked by P-8	Low auto-stop oil pressures signal
11) Steam/feedwater flow mismatch	½ steam/feedwater flow mismatch in selected coincidence with low steam generator water level	

Table 7.2-1

LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF:
ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

	COINCIDENCE CIRCUITRY AND INTERLOCKS	**COMMENTS**
	in that steam generator.	
12) Low-low steam generator water level	2/3, per loop	
13) High intermediate range nuclear flux	½, manual block permitted by P-10	Manual block and automatic reset
14) High source range nuclear flux	½, manual block permitted by P-6, block maintained by P10	Manual block and automatic reset of P-6; manual reset of P-10
CONTAINMENT ISOLATION ACTUATION		
15) Safety Injection Signal (Phase A)	See Item 9	Actuates all non-essential service containment isolation trip valve and actuates Isolation Valve Seal Water System
16) Containment pressure (Phase B)	Coincidence of two sets of 2/3 containment pressure (High-high pressure [energize to actuate], same signal which actuates containment spray), or manual 2/2	Actuates all essential service containment isolation trip valves
17) Containment ventilation (High containment activity)	½ high activity signal, from air particulate detector or radiogas detector or containment isolation phase "A" signal, or spray actuation signal	This additional signal closes containment purge supply, exhaust ducts and pressure relief duct only
ENGINEERED SAFETY FEATURES ACTUATION		
18) Safety injection signal (S)	See Item 9	
19) Containment spray signal (P)	Coincidence of two sets of 2/3 containment pressure (high-high pressure); or manual 2/2 (Note: Bistables are energize-to-operate)	
20) Spray additive valves	Coincidence of two sets of 2/3 containment pressure (high-high pressure, same signal which actuates containment spray (Note: Bistables are energize-to-operate)	
21) Containment air recirculation cooling and filtration signal	Safety injection signal initiates starting of all fans in accordance with the safety injection starting sequence, 2/3 high containment pressure or manual ½	
22) Isolation valve seal water signal	Safety injection signal	

Table 7.2-1

LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF:
ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

	COINCIDENCE CIRCUITRY AND INTERLOCKS	**COMMENTS**
STEAM ISOLATION ACTUATION		
23) Steam flow	After time delay (maximum 6 seconds) with high steam flow in 2/4 lines in coincidence with (a) low T_{avg} in 2/4 lines or (b) low steam line pressure in 2/4 lines	
24) Containment pressure	Coincidence of two sets of 2/3 Containment pressure (high-high pressure) (Note: Bistables are energize-to-operate)	
25) Manual	1/1 per steam line	
AUXILIARY FEED WATER ACTUATION		
26) Turbine driven pump	Coincidence of 2/3 low level in two steam generators; or a non-SI blackout sequence signal from 480 volt buses 3A or 6A; or manual ½; or AMSAC Actuation	
27) Motor driven pumps	2/3 low level in any steam generator; or trip of ½ main feedwater pump turbines; or safety injection signal; or manual ½; or a non-SI blackout sequence signal from 480 volt bus 3A to start pump 31; or a non-SI blackout sequence signal from 480 volt bus 6A to start pump 33; or AMSAC Actuation	
MAIN FEEDWATER ISOLATION		
28) Close main feedwater control valves, (including associated MOVs) trip main feedwater pumps	Any safety injection signal (See Item 9)	

TABLE 7.2-2

INTERLOCK AND PERMISSIVE CIRCUITS

Number	Function	Input for Blocking
1 +	Prevent rod withdrawal on overpower	¼ high nuclear flux (power range) or ½ high nuclear flux (intermediate range or ¼ overtemperature ΔT or ¼ overpower ΔT
2	Auto-rod withdrawal stop at low power	Low MWe load signal
3+	Auto-rod withdrawal stop on rod drop	¼ rapid decrease of nuclear flux (power range) or 1/1 rod bottom indication
4*	[BLANK – See Note]	
5 +	Steam dump interlock	Turbine trip signal
6	Manual block of source range level trip	½ high intermediate range flux allows manual block, 2/2 low intermediate range defeats block
7	Permissive power (block various trips required only at power)	¾ low-low nuclear flux (power range) and 2/2 low turbine impulse chamber pressure signal
8	Block single primary loop loss of flow trip and Block Reactor Trip on Turbine Trip	¾ low nuclear flux (power range)
9*		
10	Manual block of low setpoint trip (power range) and intermediate range trips	2/4 high nuclear flux allows manual block, ¾ low nuclear flux (power range) defeats manual block

NOTE:
* not applicable to this plant
+ alarmed

TABLE 7.2-3

ROD STOPS

Rod Stop	Actuation Signal	Rod Motion to be blocked
1. Rod Drop	¼ rapid power range nuclear	Automatic Withdrawal
	flux decrease or any rod bottom signal	Actuation of rod stop (Item 1) initiates a turbine load reduction above a given power level
2. Nuclear Overpower	¼ high power range nuclear flux or ½ high intermediate range nuclear flux	Automatic and Manual Withdrawal
3. High ΔT*	¼ overpower ΔT or ¼ overtemperature ΔT	Automatic and Manual Withdrawal
4. Low Power	Low turbine first stage (inlet) pressure load signals	Automatic Withdrawal
5. T_{avg} Deviation	¼ T_{avg} deviation from average T_{avg}	Automatic Withdrawal

*NOTE: Actuation of rod stop (Item 3) initiates a load cutback at any power level.

TABLE 7.2-4

TABLE OF MAIN CONTROL BOARD INDICATOR AND/OR RECORDERS "*ORIGINALLY*" AVAILABLE TO THE OPERATOR [HISTORICAL]

PARAMETER	NO. OF CHANNELS AVAIL	NO. OF CHANNELS REQUIRED	RANGE	ACCURACY REQUIRED	INDICATOR/RECORDER	PURPOSE
MODERATE & INFREQUENT FAULTS						
1. TCold or Thot (Measured, Wide range)	4THot 4 TCold	1	0-700°F	+4% of Full range	Both channels are recorded on each loop.	Ensure maintenance of proper cooldown rate to ensure maintenance of proper relationship between system pressure and temperature for NDTT considerations.
2. Pressurizer Water Level	3	2	Entire Distance Between Taps	+3% of Level at 2250 PSIA	All 3 channels indicated; one channel is selected for recording.	Ensure maintenance of proper reactor coolant inventory.
3. Reactor Coolant System Pressure (Wide range)	2	1	0-3000 psig	+6% of Full range	Indicated and recorded	Ensure maintenance of proper relationship between system pressure and temperature for NDTT consideration.

4. Containment Pressure	6	1	-5 psig to +75 psig	±3% of Full range	All 6 are indicated.	Monitor containment conditions to indicate need for potential safeguards actuation.
5. Steam Line Pressure	12 (3/Loop)	4 (1/Loop)	0-1400 psig	±3% of Full Scale	All 4 are indicated.	Monitor steam generator temperature conditions during hot shutdown and cooldown and for use in recovery from steam generator tube ruptures.
6. Steam Generator Water Level (Wide range)	4 (1/S.G.)	*	+7 to -41 feet from nominal full load water level	±5% of Level Span (Cold)	All 4 channels recorded.	Ensure maintenance of reactor heat sink.
7. Steam Generator Water Level (Narrow range)	12 (3/S.G.)	*	+7 to -5 feet from nominal full load water level	±3% of Level Span (Hot)	All 12 Channels indicated; the 4 channels used for control are recorded.	Same as 6.

Minimum Requirements: One level channel per Steam Generator (Either Wide or Narrow Range) with at least Two Wide Range Channels

TABLE 7.2-5

TABLE OF MAIN CONTROL BOARD INDICATOR AND/OR RECORDERS *"ORIGINALLY"* AVAILABLE TO THE OPERATOR [Historical]

Parameter	No. of Channels Avail	Required	Range	Accuracy Required	Indicator/Recorder	Purpose
Limiting Faults						
1. Containment Pressure	6	1	-5 psig to +75 psig	±10% of Full Scale	All 6 are indicated	Monitor Post-LOCA containment conditions.
2. Refueling Water Storage Tank Water Level	2	1	0-100% of span	±3% of level span	One is indicated and both are alarmed	Ensure that water is flowing to the safety injection system after a LOCA and determine when to shift from injection to recirculation mode.
3. Steam Generator Water Level (narrow range)	3/Steam Generator	*	+7 to -5 feet from nominal full load level	±10% of level span (1)	All channels indicated; the channels used for control are recorded	Detect steam generator tube rupture; monitor steam generator steam water level following a line break.
4. Steam Generator Water Level (wide range)	1/Steam Generator	*	+7 to -41 feet from nominal full load level	±10% of level span (1)	All channels are recorded	Detect steam generator tube rupture; monitor steam generator water level following a steam line break.

5. Steam Line Pressure	3/Steam line	1/Steam line	0-1400 psig	±5% of full scale	All channels are indicated	Monitor steam line pressures following steam generator tube rupture or steam line break.
6. Pressurizer Water Flow Level	3	2	Entire distance between taps	Indicate that level is somewhere between 0 and 100% of span	All 3 are indicated and one is for recording	Indicate that water has returned to the pressurizer following cooldown after steam generator tube rupture or steam line break.
7. RHR Recirculation Flow	4	3**	0-1000 GPM	±10% of span	All are indicated	Monitor recirculation flow.

(1) For the steam break, when the water level channel is exposed to a hostile environment, the accuracy required can be relaxed. The indication need only convey to the operator that water level in the steam generator is somewhere between the narrow range steam generator water level taps.

* Minimum Requirements: One Level Channel per Steam Generator (either Wide or Narrow Range) with at least Two Wide Range Channels.

** Three required to allow possibility of low head recirculation. None required to allow high head recirculation.

7.3 REGULATING SYSTEMS

7.3.1 Design Basis

The Reactor Control System is designed to limit nuclear plant transients for prescribed design load perturbations, under automatic control, within prescribed limits to preclude the possibility of a reactor trip in the course of these transients.

Overall reactivity control is achieved by the combination of chemical shim and 53 control rod clusters of which 29 are in 4 control banks and 24 are in 4 shutdown banks. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short-term reactivity control for power changes or reactor trip is accomplished by movement of control rod clusters.

The primary function of the Reactor Control System is to provide automatic control of the rod clusters during power operation of the reactor. The system uses input signals including neutron flux; coolant temperature and pressure; and plant turbine load. The Chemical and Volume Control System (Chapter 9) serves as a secondary reactor control system by the addition and removal of varying amounts of boric acid solution.

There is no provision for a direct continuous visual display of primary coolant boron concentration. When the reactor is critical, the best indication of reactivity status in the core is the position of the control group in relation to plant power and average coolant temperature. There is a direct, predictable, and reproducible relationship between control rod position and power and it is this relationship which establishes the lower insertion limit calculated by the rod insertion limit monitor. There are two alarm setpoints to alert the operator to take corrective action in the event a control bank approaches or reaches its lower limit. Rod position is also a function of core life.

Any unexpected change in the position of the control banks when under automatic control or a change in coolant temperature when under manual control provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, periodic samples of coolant boron concentration are taken. The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

The Reactor Control System is designed to enable the reactor to follow load changes automatically when the plant output is above 15% of nominal power. Control rod positioning may be performed automatically when plant output is above this value, and manually at any time.

Overriding the rod stop and turbine runback signals from the Overpower or Overtemperature ΔT circuitry, or from the Power Range Nuclear Instrument Dropped Rod circuitry has no impact on the prevention of automatic control rod withdrawal below 15% of nominal power. Overriding one channel of these signals has no impact on reactor protection in the event of an approach to an overpower condition in as much as the reactor trips associated with such a condition remains unaffected. Additionally, since only one channel at a time is permitted to be affected, the other three channels remain available for rod stop and turbine runback on either Overpower or Overtemperature ΔT, or on Power Range Nuclear Instrument Rod Drop signals.

The system enables the nuclear plant to accept the following transients without reactor trip subject to possible xenon limitations:

a) Step load increases to 10% within the load range of 15% to 90% of full power

b) Step load reduction of 10% within the load range of 100% to 25% of full power

c) A 5% per minute ramp load change within the load range of 15% to 100% of full power.

The operator is able to select any single bank of rods (shutdown or control) for manual operation. Using a single switch, he may not select more than one bank from these two functions. He may also select automatic reactor control, in which case, the control banks can be moved only in their normal sequence with some overlap as one bank reaches its full withdrawal position and the next bank begins to withdraw. Interlocks are provided to preclude simultaneous withdrawal of more than two banks of control rods or shutdown rods.

The control system is capable of restoring coolant average temperature to within the programmed temperature deadband, following a scheduled or transient change in load.

The reactor plant can be placed under automatic control in the power range between 15 percent of load and full load and will accept the following design transients while in automatic control:

a) Step load increases of 10% within the load range of 15% to 90% of full power (without turbine bypass)

b) Step load reductions of 10% within the load range of 100% to 25% of full power (without turbine bypass)

c) A 5% per minute ramp load change within the load range – 15% to 100% of full power (without turbine bypass)

d) A -10% to -50% change in load, at a maximum turbine unloading rate of 200% per minute, from approximately 100% load with steam dump (load rejection capability depends on full power Tavg; see Section 7.3.2) (with turbine bypass).

A programmed pressurizer water level as a function of T_{avg} is provided to minimize the requirements of the Chemical and Volume Control and Waste Disposal Systems resulting from coolant density changes during loading and unloading from full power to zero power.

Following a reactor and turbine trip, sensible heat stored in the reactor coolant is removed without actuation of steam generator safety valves by means of controlled steam bypass to the condenser and by injection of feedwater to the steam generators. Reactor Coolant System temperature is reduced to the no load condition. This no load coolant temperature is maintained by steam bypass to the condensers to remove residual heat.

The control system is designed to operate as a stable system over the full range of automatic control throughout core life without requiring operator adjustment of set points other than normal calibration procedures.

7.3.2 <u>System Design</u>

A block diagram of the Reactor Control System is shown in Figure 7.3-1.

Rod Control

There are 53 total RCC assemblies. The assemblies are grouped into (1) 4 shutdown banks having rod clusters of 8, 8, 4, 4, rod clusters and (2), 4 control banks 8, 4, 8 and 9 rod clusters.

Figure 3.2-1 shows the location of the RCC assemblies in the core. The four control banks are the only rods that can be manipulated under automatic control. The banks are divided into groups to obtain smaller incremental reactivity changes. All RCC assemblies in a group are electrically paralleled to step simultaneously. Position indication for each RCC assembly type is the same.

Control Group Rod Control

The Reactor Control System is capable of restoring programmed average temperature following a scheduled or transient change in load. The coolant average temperature is programmed to increase linearly from zero power to the full power conditions.

The control system will also compensate initially for reactivity changes caused by fuel depletion and/or xenon transients. Final compensation for these two effects is periodically made with adjustments of boron concentration. The control system then readjusts the control rods in response to changes in coolant average temperature resulting from changes in boron concentration.

The coolant average temperatures are measured from the hot leg and the cold leg in each reactor coolant loop. The average of the four measured average temperatures is the main control signal. This signal is sent to the control rod programmer through a proportional plus rate compensation unit. The control rod programmer commands the direction and speed of control rod motion. A compensated pressurizer pressure signal, and a power-load mismatch signal are also employed as control signals to improve the plant performance. The power-load mismatch channel takes the difference between nuclear power (average of all four power range channels) and a signal of turbine load (first stage (inlet) turbine pressure), and passes it through a high-pass filter such that only a rapid change in flux or power causes rod motion. The pressure compensation and the power-load mismatch compensation serve to speed up system response and to reduce transient peaks.

The control bank rods are divided into four banks comprising 8, 4, 8 and 9 RCC assemblies respectively, to follow load changes over the full range of power operation. Each control rod bank is driven by a sequencing, variable speed rod drive control unit. The assemblies in each control bank are divided into two groups. The groups are moved sequentially one step at a time. The sequence of motion is reversible, that is, a withdrawal sequence is the reverse of the insertion sequence. The variable speed sequential rod control affords the ability to insert a small amount of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband. Any reactor trip signal causes the rods to drop by gravity into the core.

Manual control is provided to manually move a control bank in or out at a preselected fixed speed.

Proper sequencing of the RCC assemblies is assured: first, by fixed programming equipment in the Rod Control System, and second, through administrative control of the reactor plant operator. Startup of the plant is accomplished by first manually withdrawing the shutdown rod banks to the full out position. This action requires that the operator select the SHUTDOWN BANK position on a control board mounted selector switch and then position the IN-HOLD-OUT level (which is spring return to the HOLD position) to the OUT position.

RCC assemblies are then withdrawn under manual control of the operator by first selecting the MANUAL position on the control board mounted selector switch and then positioning the IN-HOLD-OUT LEVER to the OUT position. In the MANUAL selector switch position, the rods are withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

When the reactor power reaches approximately 15% of rated power, the operator may select the AUTOMATIC position, where the IN-HOLD-OUT lever is taken out of service, and rod motion is controlled by the Reactor Control and Protection Systems. A permissive interlock limits automatic control to reactor power levels above 15%. In the AUTOMATIC position, the rods are again withdrawn (or inserted) in a programmed sequence by the automatic programming equipment.

Programming is set so that as the first bank out (control bank A) reaches a preset position, the second bank out (control bank B) begins to move out simultaneously with first bank. When control bank A reaches the top of the core, it stops, and control bank B continues until it reaches a preset position near the top of the core where control bank C motion beings, etc. The withdrawal sequence continues until the plant reaches the desired power level. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank out is the first control bank in.

With the simplicity of the rod program, the minimal amount of operator selection, and two separate direct position indications available to the operator, there is very little possibility that rearrangement of the control rod sequencing could be made.

Shutdown Rod Control

The shutdown rods together with the control rods are capable of shutting the reactor down. They are used in conjunction with the adjustment of chemical shim to provide shutdown margin of at least one percent following reactor trip with the most reactive control rod in the fully withdrawn position for all normal operating conditions. The shutdown banks are manually controlled during normal operation and are moved at a constant speed with staggered stepping of the groups within the banks. Any reactor trip signal causes them to drop by gravity into the core. They are fully withdrawn during power operation and are withdrawn first during startup. Criticality is always approached with the control rods after withdrawal of the shutdown banks. Four shutdown banks with a total of 24 clusters are provided.

Interlocks

The rod control group is used for automatic control and is interlocked with measurements of turbine-generator load to prevent automatic control rod withdrawal below 15% of nominal power. The manual and automatic controls are further interlocked with measurements of neutron flux, ϵT and rod drop indication to prevent approach to an overpower condition.

Rod Drive Performance

The control banks are driven by a sequencing, variable speed rod drive programmer. In each control bank of RCC assemblies, two groups (each containing a small number of RCC assemblies) are moved sequentially in a cycle such that both groups are maintained within one step of each other.

The sequence of motion is reversible, that is, withdrawal sequence is the reverse of the insertion sequence. The sequencing speed is proportional to the control signal from the Reactor Control System. This provides control group speed control proportional to the demand signal from the control system.

The output of two paralleled motor generator (M-G) sets provides power to the rod drive mechanism coils through a solid state control system. Two reactor trip breakers are placed in series with the output of the M-G sets. To permit on-line testing, a bypass breaker is provided across each of the two breakers.

RCCA Position Indication

Two separate systems are provided to sense and display control rod position as described below:

a) Analog System – An analog signal is produced for each individual rod by a linear position transmitter.

   An electrical coil stack is located above the stepping mechanisms of the control rod magnetic jacks, external to the pressure housing, but concentric with the rod travel. When the associated control rod is at the bottom of the core, the magnetic coupling between the primary and secondary coil winding of the detector is small and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is obtained.

   Direct, continuous readout of every control rod is presented to the operator on individual indicators.

   A deviation monitor alarm is actuated if an individual rod position deviates from its relative bank position by a preselected distance.

   Lights are provided for rod bottom positions for each rod. The lights are operated by bistable devices in the analog system.

b) Digital System – The digital system counts pulses generated in the rod drive control system. One counter is associated with each group of control and shutdown rods. Readouts of the digital system are in the form of electromechanical add-subtract counters reading the number of steps of rod movement with one display for each group. These readouts are mounted on the control panel.

The digital and analog systems are separate systems; each serves as backup for the other. Operating procedures require the reactor operator to compare the digital and analog readings upon recognition of any apparent malfunction. Therefore, a single failure in rod position

indication does not in itself lead the operator to take erroneous action in the operation of the reactor.

Full Length Rod Drive Power Supply

The full length control rod drive power supply concept, using a single trip bus system, has been successfully employed on all Westinghouse PWR Plants. Potential fault conditions with a single trip bus system are discussed in this section. The unique characteristics of the latch type mechanisms with its relatively large power requirements makes this system with the redundant series trip breakers particularly desirable.

The solid state rod control system is operated from two parallel connected 438 kVA generators which provide 260 volt line to line, three phase, four wire power to the rod control circuits through two series connected reactor trip breakers.

This AC power is distributed from the trip breakers to a line-up of identical solid state power cabinets and a DC holding cabinet using a single overhead run of enclosed bus duct which is bolted to and therefore comprises part of the power cabinet arrangement. Alternating current from the motor-generator sets is converted to a pulsed direct current by the power cabinet and is then distributed to the mechanism coils. Each complete rod control system includes a single 125/70 volt DC power supply which is used for holding the mechanisms in position during maintenance of normal power supply.

This 125/70 volt supply, which receives its input from the AC power source downstream of the reactor trip breakers, is distributed to each power cabinet and permits holding mechanisms in groups of four by manually positioning switches located in the power cabinets. The 70/40 ampere output capacity limits the holding capability to eight rods.

Reactor Trip

Current to the mechanisms is interrupted by opening either of the reactor trip breakers. The 125/70 volt DC maintenance supply will also be interrupted since this supply receives its input power through the reactor trip breakers.

Trip Breaker Arrangement

The trip breakers are arranged in the reactor trip switchgear in individual metal enclosed compartments. The 1000 ampere bus work, making up the connections between trip breakers are separated by metal barriers to prevent the possibility that any conducting objects could short circuit, or bypass, trip breaker contacts.

Maintenance Holding Supply

The 125/70 volts DC holding supply and associated switches have been provided to avoid the need for bringing a separate DC power source to the rod control system during maintenance on the power cabinet circuits. This source is adequate for holding a maximum of five mechanisms and satisfies all maintenance holding requirements.

Control System Construction

The rod control system equipment is assembled in enclosed steel cabinets. Three phase power is distributed to the equipment through a steel enclosed bus duct, bolted to the cabinets. DC power connections to the individual mechanisms are routed to the reactor head from the solid state cabinets through insulated cables, enclosed junction boxes, enclosed reactor containment penetrations, and sealed connectors. In view of this type of construction, an accidental connection of either an AC or DC power source, either internal or external to the cabinets, is not considered credible.

AC Power Connections

The three phase four wire supply voltage required to energize the equipment is 260 volts line to line, 58.2 Hz, 438 kVA capacity, zig-zag connected. It is unlikely that any power supply, and in particular one as unusual as this four wire power source could be accidentally connected, in phase, in the required configuration. Also it should be noted that this requires multiple connections, not single connections. The closest outside sources available in the plants are 480 volt auxiliary power source and 208 volt lighting source.

Connections of either a 480 or 208 volt, 60 Hz source to the single AC bus supplying the rod control system causes currents to flow between the sources due to an out of phase condition. These currents flow until the generator accelerates to a speed synchronous with the 60 Hz outside source, a time sufficient to trip the generator breakers. The out-of-phase currents for an unlimited capacity outside source, an outside source with a capacity equivalent to the normal generator kVA, and for either one or two M-G sets in service are tabulated below:

Out of Phase Currents (Amperes)

	One M-G Set in Service	Two M-G Sets In Service
480 volts		
Unlimited Capacity	25,000	50,000
438 kVA Capacity	12,000	25,000
208 volts		
Unlimited Capacity	16,000	32,000
438 kVA Capacity	8,000	16,000

All of the foregoing currents are sufficiently high to trip out the generator breakers on either overcurrent or reverse current. This trip-out is detectable by annunciation in the Control Room. If the outside power source trips, the connection is of no concern.

Each solid state power cabinet is tied to the main AC bus through three fused disconnect switches; one for the stationary gripper coil circuits, one for the movable gripper coil circuits, and one for the lift coil circuits. Reference voltage to operate the control circuits for all three coil circuits must be in phase with the supply to all coil circuits for proper operation of the system. If the outside power source were brought into an individual cabinet, nine (9) normal source connections would have to be disconnected and the outside source would have to be tied in phase to the proper nine (9) points plus one (1) neutral point to allow movement of the rods. This is not considered credible.

Connection of a single phase AC source (i.e., one line to neutral) is also considered improbable. This would again require a high capacity source which would have to be connected in-phase with the non-synchronous M-G set supply. Again, more than one connection is needed to achieve this condition. Each power cabinet contains three alarm circuits (stationary, movable and lift) that would annunciate the condition to the operator. In addition, calculations show that a single phase source of 208 volts, 260 volts, or 480 volts will not supply enough current to hold the rods. Therefore, a jumper across two trip circuit breaker contacts in series which results in a single phase remaining closed would not provide sufficient current to hold up the rods.

The normal source generators are connected in a zig-zag winding configuration to eliminate the effects of direct current saturation of the machines resulting from the direct currents that flow in the half wave bridge rectifier circuits. If this connection were not used, the generator core would saturate and loss of generating action would occur. This condition would also occur in a transformer. An outside source not having the zig-zag configuration would have to have a large capacity (400 kVA) to avoid the loss of transformer action from saturation.

Most of the components in the equipment are applied with a 100% safety factor. Therefore, the possibility exists that the system will operate at 480 volts with a source of sufficient capacity. The system will definitely operate at 208 volts with a source of sufficient capacity.

The connection of an outside source of AC power to one rod control system would first require a need for this source. No such need exists since two power sources (M-G sets) are already provided to supply the system. If the source were connected in spite of the need, extreme measures would have to be taken by the intruder to complete the connection. The outside source would have to be a large capacity (400 kVA) one. The currents that flow would require the routing of large conductors or bus bars, not the usual clip leads. Then the disassembly of switchgear or enclosed bus duct would be required to expose the single AC bus. Large bolted cable or bus bar terminations would have to be completed. A total of four conductors would have to be connected in phase with a non-synchronous source. To expect that a connection could be completed with the equipment either energized or de-energized in view of the obstacles which would prevent such a connection is incredible.

However, even if the connection were completed, the outside source connection would be detectable by the operator through the tripping of the generator breakers.

DC Power Connections

An external DC source could, if connected inside the power cabinet, hold the rods in position. This would require a minimum supply voltage of 50 volts. Since the holding current for each mechanism coil is 4 amperes, the DC current capacity would have to be approximately 180 amperes to hold all rods. Achieving this situation would require several acts – bringing in a power source which is not required for any type of operation in the rod control system, preferentially connecting it into the system at the correct points, and actuating specific holding switches so as to interconnect all rods. Closure of twelve switches in four separate cabinets would be required to hold all rods. One switch could hold as many as four rods.

The application of a DC voltage to an individual rod external to the power cabinet would affect only a single rod connection with other rods in the group being prevented by the blocking diodes in the power circuits.

Should an external DC source be connected to the system, the system is provided with features to permit its detection.

Each solid state power cabinet contains circuitry which compares the actual currents in the stationary and movable gripper coils with the reference signals from the step sequencing unit (slave cycler). In taking a single step, the current to the stationary gripper coil will be profiled from the holding value to the maximum, to zero and return to holding level. Correspondingly, the movable gripper coil must change from zero to maximum and return to zero. The presence of an external DC source on either the stationary or movable would prevent the related currents from returning to zero.

This situation would be instantaneously annunciated by way of the comparison circuit. Therefore, any rod motion would actuate an alarm indicating the presence of an external DC source. In addition, an external DC source would prevent rods from stepping. Thus, an external source could be detected by the rod position indication system indicating failure of the rod(s) to move.

Connection of an external DC power source to the output lines of the 125/70 volt DC power supply can be detected by opening the three phase primary input of the supply and checking the output indication lights.

Evaluation Summary

In view of the preceding discussion, the postulated connection of an external power source (either AC or DC) or occurrence of short circuits that could prevent dropping of the rods is not considered credible.

Specifically:

a) The need for an outside power source has been eliminated by incorporating built-in holding sources as part of the rod control system and by providing two M-G sets.

b) The equipment is contained within enclosed steel cabinets precluding the possibility of an accidental connection of either AC or DC power in the cabinets.

c) AC power distribution is accomplished using steel enclosed bus duct. The high capacity (438 kVA) AC power source is unique and not readily available. Multiple connections are required.

d) DC power is distributed to the individual mechanisms through insulated cables and enclosed electrical connections precluding the accidental connection of an outside DC source external to the cabinets. The high capacity DC source required to hold rods is not readily available in the rod control system, would require multiple connections, and would require deliberate positioning of switches within the enclosed cabinets.

e) Provisions are made in the system to permit detection of an external DC source which could preclude a rod release.

The total capacity of the system including the overload capability of each motor generator set is such that single set out of service does not cause limitations in rod motion during normal plant

operation. In order to minimize reactor trip as a result of a unit malfunction, the power system is normally operated with both units in service.

Turbine Bypass

A turbine bypass system is provided to accommodate a reactor trip with turbine trip and in conjunction with automatic reactor control can accommodate a load rejection without reactor and turbine trip. The maximum load rejection that can be accommodated without reactor and turbine trip depends on the full load Tavg. A maximum of a 10% load rejection can be accommodated for the minimum acceptable full load Tavg of 550.6°F. As the full load Tavg is increased, larger load rejections can be accommodated. For full load Tavg values of 565 °F or higher, load rejections of 50% can be accommodated. The turbine bypass system removes steam to reduce the transient imposed upon the reactor coolant system so that the control rods can reduce the reactor power to a new equilibrium value without allowing overtemperature, overpressure conditions in the Reactor Coolant System.

The steam dump is actuated by an electrical load decrease rate greater than a preset value. This signal supplies air to the dump valves, which then allows them to open and close according to the temperature error signal, a compensated ($T_{avg} - T_{ref}$) signal. The dump valves modulate open proportionally to this temperature error signal with a stroke time of approximately 20 seconds. For large temperature errors the valves will trip open in two banks as required for fast response with a stroke time of about three seconds. Upon reduction of the error signal below the trip-open setpoints, the respective valve groups return to modulating control.

The steam dump decreases proportionally as the control rods act to reduce the coolant average temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed value. When steam dump is no longer required, the air supply to the valves may be manually removed.

Since the steam dump valves exhaust into the condenser, all steam dump is blocked when the condenser in unavailable.

The turbine bypass steam system is described in Section 10.2. The bypass flows to the main condenser.

Feedwater Control

Each steam generator is equipped with two three element feedwater control systems (one for the main regulator valve and the second for the low flow regulator valve) which maintain a programmed water level as a function of load on the secondary side of steam generator. The three element feedwater control system continuously compares actual feedwater flow with steam flow compensated by steam pressure with a water level set point to regulate the feedwater valve opening. The individual steam generators are operated in parallel, both on the feedwater and on the steam side.

Continued delivery of feedwater to the steam generator is required as a sink for the heat stored and generated in the coolant following a reactor trip and turbine trip. A reactor trip signal provides an override signal to the feedwater control system. After a trip, all feedwater valves open fully thereby insuring the full supply of feedwater following a reactor trip and turbine trip. Another override signal then closes the feedwater valves when the coolant average temperature

falls below a preset temperature value or when the respective steam generator level rises to a preset value. Manual override of the feedwater control systems is also provided.

Pressure Control

The reactor coolant system pressure is maintained at constant value by using heaters in the water region and spray in the steam region of the pressurizer. Electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater groups are proportional heaters and are used for small pressure variation control and to compensate for heat losses and the smaller continuous spray. Up to three sets of backup heaters may be turned on manually and operated continuously. The remaining (backup) heaters are turned on either when the pressurizer pressure controller signal is below a preset value or when the pressurizer level exceeds the programmed level setpoint by a preset amount.

The spray valves for the pressurizer are located near their respective RCS cold legs, and the spray nozzle is located at the top of the pressurizer. Spray is initiated when the pressure controller signal is above a preset set point. Spray rate increases proportionally with increasing pressure until it reaches the maximum spray capacity.

Steam condensed by spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stress and thermal shock when the spray valves open and help maintain uniform water chemistry and temperature in the pressurizer.

Two power operated relief valves (PORVs), PCV-455C and PCV-456, prevent the RCS pressure from exceeding the Technical Specifications limits of 10 CFR 50 Appendix "G" during low temperature, low pressure and water solid modes of operation. The PORVs are armed below a preset temperature of 319°F, and will open at a programmed pressure which is set to prevent exceeding the Appendix "G" curves. The two PORVs are supplied with nitrogen. The instrument N_2 system for the PORVs is tapped from the N_2 supply line to the four safeguards accumulators. The accumulators are sized to provide for 200 valve operating cycles. The actual take-off point for this N_2 system is downstream of the pressure regulator valve NNE-863. The PORV accumulators individually hold 6 cu ft of N_2 at a minimum pressure of 550 psig. During low temperature shutdown operations, the Overpressure Protection System requires an N_2 supply of sufficient capacity which, in case of loss of main N_2 supply, can support the number of PORV cycles resulting from an overpressure event of 10 minute duration. This N_2 supply is provided by one Safety Injection Accumulator having its associated N_2 fill valve blocked open.

One PORV is operated on the pressurizer pressure controller signal, the other one is operated on the actual pressure signal. A separate interlock is provided for each so that if a second pressure channel indicates abnormally low, are the time the relief valve operation is called for by the other channel, the valve activation is blocked. The logic for each is thus basically two out of two. However, during normal operation at normal pressure, the interlock is not actuated and only the operating signals are required to actuate the valve. The interlock is set above normal operating pressure to prevent spurious operation.

Three spring-loaded safety valves limit system pressure to 2750 psia following a complete loss of load without direct reactor trip or actuation of turbine bypass.

Reactor coolant flow to the residual heat removal loop is from the hot leg of Loop 2 through two motor operated valves (No. 731 and 730). Valves 731 and 730 are pressure interlocked to prevent opening should reactor coolant pressure go above 450 psig. This arrangement

prevents inadvertent pressurization of the residual heat removal loop when the Reactor Coolant System is above 450 psig. These valves will be opened when RCS pressure is lower than 450 psig. Valve position indication lights and position selector switches for both valves are provided in the control room. These valves are closed during power operation to preclude RHRS over-pressurization. To open the valve, the switch is held over to the Open position and if RCS pressure is less than 450 psig, the valve will open. If these valves are open and RCS pressure increases to 550 psig, they will auto-close. A narrow range pressure recorder with an operator controlled alarm point, which actuates warning lights and audible device, has been added to instrument loop for PT-402. This is designed to attract the operators attention to a potential overpressure transient in progress, to allow him to take necessary action to minimize the magnitude of overpressure event while the RCS is operating at low pressure. The system is not required for safe shutdown of the reactor, and the operator may deactivate the recorder and alarms, which removes the potential for distracting alarms when a normal RCS pressure.

To prevent inadvertent isolation of the RHR loop when the Reactor Coolant System is below 200 degrees, depressurized, and vented to an equivalent opening of greater than two (2) square inches AC-MOV-730 and 731 may be de-energized open.

These valves are also interlocked with containment sump valves 885A and B. To open valves 885A and B, the RHR suction valves 730 and 731, respectively, must be closed. This prevents the reactor coolant water from being drained to the contained sump. High Head SI Suction Valves 888A and B are also interlocked with valves 730 and 731, respectively. A valve 884A and B will not open if 730 and 731, respectively, are opened.

SI-MOV-883 is interlocked with AC-MOV-730 and AC-MOV-731 so that the valve can only be opened if both MOV-730 and MOV-731 are fully closed. If valve SI-MOV-883 is open and valve AC-MOV-730 or AC-MOV-731 leave their closed limit seats, valve SI-MOV-883 will auto-close. The interlock prevents inadvertent opening of valve SI-MOV-883 during cool down and subsequent diversion of reactor coolant to the RWST or over pressurization of a lower pressure SI piping system.

Valves AC-MOV-730 and -731 may be de-energized during cold shutdown if the RCS is depressurized and vented through a minimum equivalent opening of two (2) square inches. De-energizing these valves while the RHR pumps are in service prevents inadvertent isolation of the RHR pump suction supply, which could potentially cause pump failure. De-energizing these valves will also cause a loss of all of the interlock protection associated with AC-MOV-730 and -731. When AC-MOV-730 and –731 are de-energized, administrative controls are established to replace the protective functions of these interlocks. These administrative controls prevent unanticipated communication of reactor coolant with the containment sump and the RWST. These controls also prevent overpressurization of the RHR and SI system piping and components.

7.3.3 System Design Evaluation

Plant Stability

The control system is designed to maintain a stable reactor coolant average temperature within acceptable limits. Continuous oscillation at a low frequency and small amplitude is expected. Proper adjustment of the control loop static and dynamic gains (with respect to the process response) can reduce this oscillation almost to zero and will also avoid instability induced by the control system itself. Because stability is more difficult to maintain at low power under

automatic control, no provision is made to provide automatic control below 15 percent of full power.

The control system is designed to operate as a stable system over the full range of automatic control throughout core life.

Step Load Changes Without Turbine Bypass

A typical reactor power automatic control requirement is to restore equilibrium conditions without a plant trip, following 10 percent step load demand increases within the range of 15 to 90 percent of full power and 10% step load demand reductions within the range of 100% to 25% of full power. The design was necessarily based on conservative conditions and a greater transient capability is expected for actual operating conditions. A load demand greater than full power is inhibited by the turbine control load limit devices in response to input from the Reactor Protection System. Although turbine bypass is provided for added control after large load decreases, it will not be necessary during the 10% load changes.

The function of the control system is to minimize the reactor coolant average temperature deviation during the transient within an acceptable value and to restore average temperature to the programmed set point within an acceptable time. Excessive pressurizer pressure variations are prevented by using spray and heaters in the pressurizer.
The margin to over-temperature ΔT reactor trip is of primary concern for the step load changes. This margin is influenced by nuclear flux, pressurizer pressure, and reactor coolant average temperature and temperature rise across the core.

Ramp Loading and Unloading

Ramp loading and unloading is provided over the 15 to 100 percent power range under automatic control. The function of the control system is to maintain the coolant average temperature and the secondary steam pressure as functions of turbine-generator load within acceptable deviation from the programmed values. The minimum control rod speed provides a sufficient reactivity rate to compensate the reactivity changes resulting from the moderator temperature coefficient and the power coefficient.

The coolant average temperature is increasing during loading and there is a continuous in-surge to the pressurizer resulting from coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous out-surge from the pressurizer resulting from coolant contraction. The heaters limit the resulting system pressure decrease. The pressurizer level is programmed such that the water level has an acceptable margin above the low level heater cutout set point during the loading and unloading transients.

The primary concern for the loading is to limit the overshoot in coolant average temperature to provide sufficient margin to the over-temperature ΔT trip.

The automatic load controls are designed to safely adjust the unit generation to match load requirements within the limits of the unit capability and licensed rating.

Loss of Load With Turbine Bypass

The Reactor Control System is designed to accept a 10% to 50% (depending on full power Tavg; see Section 7.3.2) loss of load accomplished as a turbine runback at a maximum rate of 200% per minute without requiring a reactor trip. The automatic turbine bypass system is able to accommodate this abnormal load rejection by reducing the thermal transient imposed upon the reactor coolant system. The reactor power is reduced at a rate consistent with the capability of the rod control system. The reducing of the reactor power is automatic down to 15 percent of full power. Manual control is used when the power is below this value. The steam bypass is removed as fast as the control rods are capable of inserting negative reactivity.

The pressurizer relief valves might be actuated for the most adverse conditions, e.g., the most negative Doppler coefficient, and the minimum incremental rod worth. The relief capacity of the power operated relief valves is sized large enough limit the system pressure to prevent actuation of high pressure reactor trip for the most adverse conditions.

Turbine-Generator Trip With Reactor Trip

Turbine-generator unit trip is accompanied by reactor trip. With a secondary system design pressure of 1100 psia, the plant is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the saturation temperature corresponding to the steam generator safety valve set point. This, together with the fact that the thermal capacity in the Reactor Coolant System is greater than that of the secondary system, requires a heat sink to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for turbine and reactor trip from full power.

This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of cold feedwater to the steam generators. The turbine bypass system is controlled from the reactor coolant average temperature signal whose reference set point is reset upon trip to the no load value. Turbine bypass actuation must be rapid to prevent steam generator safety valve actuation. With the bypass valves open the coolant average temperature starts to reduce quickly to the no load set point. The automatic control of reactor coolant average temperature acts to proportionally close the valves and thus minimize the total amount of steam bypassed.

Following turbine trip, the steam voids in the steam generators will collapse and the fully opened feedwater valves will provide sufficient feedwater flow to restore water level in the downcomer. The feedwater flow is cut off if the reactor coolant average temperature decreases below a preset temperature value or if the steam generator water level reaches a preset high set point.

Additional feedwater makeup may then be controlled manually to restore and maintain steam generator level while maintaining the reactor coolant at the no load temperature. Long term residual heat removal is maintained by the steam generator pressure controller (manually selected) which controls the steam pressure (and thus, indirectly, the temperature) by adjusting the amount of turbine bypass to the condensers. The controller operates the same bypass valves to the condensers which are controlled by coolant average temperature during the initial transient following turbine and reactor trip.

The pressurizer pressure and water level fall very fast during the transient resulting from the coolant contraction. If heaters become uncovered following the trip, the Chemical and Volume Control System will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to heat up pressurizer water and restore pressurizer pressure to normal.

The turbine bypass and feedwater control systems are designed to prevent the coolant average temperature falling below the programmed no load temperature following the trip to ensure adequate reactivity shutdown margin.

7.4 EXCORE NUCLEAR INSTRUMENTATION

7.4.1 Design Bases

The General Design Criteria presented and discussed in this section are those which were in effect at the time when Indian Point 3 was designed and constructed. These general design criteria, which formed the basis for the Indian Point 3 design, were published by the Atomic Energy Commission in the Federal Register of July 11, 1967, and subsequently made a part of 10 CFR 50.

The Authority has completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with some of the provisions of the Commission's Confirmatory Order of February 11, 1980. The detailed results of the evaluation of compliance of Indian Point 3 with the General Design Criteria presently established by the Nuclear Regulatory Commission (NRC) in 10 CFR 50 Appendix A, were submitted to NRC on August 11, 1980, and approved by the Commission on January 19, 1982. These results are presented in Section 1.3.

Fission Process Monitors and Controls

Criterion: Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core. (GDC 13 of 7/11/67)

The excore Nuclear Instrumentation System is provided to monitor reactor power from source range, through intermediate range and power range, up to 120 percent of full power. The system provides indication, control and alarm signals for reactor operation and protection.

Additionally, per Regulatory Guide 1.97 requirements, an Excore Neutron Flux Monitoring System (NFMS) (see Plant Drawing 9321-LL-96553 [Formerly Figure 7.4-4]) consisting of two detectors has been installed to provide reactor power indication from source range through power range. The Regulatory Guide 1.97 excore Neutron Flux Monitoring System provides local indication elsewhere in the plant, in addition to indication only provided to the control room via QSPDS and CFMS. These other indication locations are in the upper electrical tunnel and at the charging station in the PAB for use during shutdown from outside the control room.

The operational status of the reactor is monitored from the Control Room. When the reactor is subcritical (i.e., during cold or hot shutdown, refueling and approach to criticality) the relative reactivity status (neutron source multiplication) is continuously monitored and indicated by proportional counter detectors located in instrument wells in the primary shield adjacent to the reactor vessel. Two source range detector channels are provided for supplying information on multiplication while the reactor is subcritical. A reactor trip is actuated from either channel if the neutron flux level becomes excessive. This system is checked prior to operations in which criticality may be approached. This is accomplished by the use of an incore source to provide a meaningful count rate even at the refueling shutdown condition. Any appreciable increase in the neutron source multiplication is slow enough to give ample time to start corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical

When the reactor is critical, means for showing the relative reactivity status of the reactor are:

1) Rod Position

2) Source, Intermediate and Power Range Detector Signals

3) Qualified Safety Parameters Display System (QSPDS)

4) Boron Concentration

5) Hot Leg Temperatures

The position of the control banks is directly related to the reactivity status of the reactor when at power, and any unexpected change in the position of the control banks under automatic control or change in the hot leg coolant temperature under either manual or automatic control provides a direct and immediate indication of a change in the reactivity status of the reactor. Periodic samples of the coolant boron concentration are taken. The variation in concentration during core life provides a further check on the reactivity status of the reactor including core depletion.

High nuclear flux protection is provided both in the power and intermediate ranges by reactor trips, actuated from either range, if the neutron flux level exceeds trip set-points. When the reactor is critical, the best indication of the reactivity status in the core (in relation to the power level and average coolant temperature) are the control room display of the rod control group position and the boron concentration in the coolant.

7.4.2 System Design

Nuclear Instrumentation System (NIS)

The three instrumentation ranges of the Nuclear Instrumentation System (NIS) overlap so that continuous readings are available during transition from one range to another. The sensitivities of the neutron detectors are illustrated on Figure 7.4-1. The Nuclear Instrumentation System diagram is shown on Figure 7.4-2.

Detectors

The excore system consists of twelve independent detectors in six instrument wells located around the reactor, as shown in Figure 7.4-3. The six assemblies provide the following instrumentation:

1. Power Range

   This range consists of four independent, long, uncompensated ionization chamber assemblies. Each assembly is made up of two sensitive lengths. One sensitive length covers the upper half of the core, and the other length covers the lower half of the core.

   In effect the arrangement provides a total of eight separate ionization chambers approximately one-half the core height. The eight uncompensated (guard-ring) ionization chambers sense thermal neutrons in the range from 5.0×10^{2} to 1.0×10^{11} neutrons per sq cm per sec.

   Each chamber initially had a nominal sensitivity of 3.1×10^{-13} amperes per neutron per sq cm (see Figure 7.4-1). The four long ionization chamber assemblies are located in vertical instrument wells adjacent to the four "corners" of the core. The

assembly is manually positioned in the assembly holders and is electrically isolated from the holder by means of insulated standoff rings.

Due to redesign of the Nuclear Core (low leakage core design) and resultant decrease in thermal neutrons at the detectors, new Power Range Moderators have been installed on the four (4) Power Range uncompensated ionization chambers. The Power Range Moderators increase the normal sensitivity of the chambers by approximately 700%.

2. Startup Range (Intermediate and Source)

There are two separate startup range assemblies. Each assembly contains one compensated ionization detector (intermediate range) and one proportional counter detector (source range).

The source range neutron detectors are proportional counters with an initial nominal sensitivity of 10 counts per sec per neutron per sq cm per sec (see Figure 7.4-1). The detectors sense thermal neutrons in the range from 10^{-1} to 5. x 10^{5} neutrons counts per second. The range of the source range channel is 10^{0} to 10^{6} counts per second.

The Source Range detectors are positioned in detector assembly containers by means of a linear, high density moderator insulator. The detector and insulator units are packaged in a housing which is inserted into the detector wells. The detector assembly is electrically isolated from the detector well by means of insulated stand-off rings.

The intermediate range neutron detectors are compensated ionization chambers that sense thermal neutrons in the range form 2.5 x 10^{2} to 2.5 x 10^{10} neutrons per sq cm per sec and initially had a nominal sensitivity of 4 x 10^{-14} amperes per neutron per sq cm per second (see Figure 7.4-1). They produce a corresponding direct current of 10^{-11} to 10^{-3} amp. These detectors are located in the same detector assemblies as the proportional counters for the source range channels.

Other than the source range pre-amplifier, which is located in containment, the electronic components for each of the source, intermediate and power range channels for the NIS are contained in a draw-out- panel mounted in racks in the Control Room.

Power Range Channel

There are three sets of power range measurements. Each set utilizes four individual currents as follows:

a) Four currents directly from the lower sections of the long ionization chambers

b) Four currents directly from the upper sections

c) Four total currents of (a) and of (b), equivalent to the average of each section.

For each of the four currents in (a) and (b), the current measurement is indicated directly by a microammeter, and isolated signals are available for control console indication and recording. An analog signal proportional to individual currents is transmitted through buffer amplifiers to the

overtemperature ΔT channel and provides automatic reset of the trip point for these protection functions. The total current, equivalent to the average, is then applied through a linear amplifier to the bistable trip circuits. The amplifiers are equipped with gain and bias controls for adjustment to the actual output corresponding to 100 percent of rated reactor power.

Each of the four amplifiers also provides amplified isolated signals to the main control board for indication and for use in the Reactor Control System. Each set of bistable trip outputs is operated as a two-out-of-four coincidence to initiate a reactor trip. Bistable trip outputs are provided at low and high power set points depending on the operating power. To provide more protection during startup operation the low range power bistable is used. This trip is manually blocked after a permissive condition is obtained by two of four power range channels. The high power trip bistable is always active.

The overpower trip is set so that, with the maximum instrumentation and bistable set point error, the maximum reactor overpower condition will be limited to 118 percent. This limit is accomplished by the use of solid state instrumentation and long ionization chambers, which permit an integration of the flux external to the core over the total length of the core, thereby reducing the influence of axial flux distribution changes due to control rod motion.

The ion chamber current of each detector is measured by sensitive meters with an accuracy of 0.5 percent. A shunt assembly and switch in parallel with each meter allow selection of one of four meter ranges. The available ranges are 0-100, 0-500, 0-1,000 and 0-5,000 microamperes. The shunt assemblies are designed in such a manner that they will not disconnect the detector current to the summing assembly upon meter failure or during switching. An isolation amplifier provides an analog signal proportional to ion chamber current for recording, data logging and delta flux indication. A test calibration unit provides necessary swtiches and signals for checking and calibrating the power range channels.

The linear amplifier accepts the output currents from each of the two chamber sections and derives a nuclear power signal proportional to the summed direct currents. This unit amplifies the currents and converts the normal current signal to a voltage signal suitable for operation of associated components such as bistables and isolation amplifiers.

Multiple power supplies furnish necessary positive and negative voltages for the individual channels and detector power.

Mounted on the front panel of each power range channel drawer are the ion chamber current meters, the shunt selector switches with appropriate positions, and the nuclear power indicator (0 to 120 percent of full power).

The isolated nuclear power signals are available for recording by the nuclear instrumentation system recorder. An isolated nuclear power signal is available for recording overpower conditions up to 200% of full power.

Alarm signals for dropped-rod-rod stop, overpower-rod stop, overpower (low and high range)-reactor trips, and channel tests are annunciated on the main control board. Control signals which are sent to the reactor control and protection system include dropped-rod-rod stop, overpower-rod stop, overpower-reactor trip, and permissive circuit signals. These are described in Section 7.2

Over-riding the turbine runback and rod stop signals from a Power Range Nuclear Instrument Dropped Rod circuit in a single channel, or over-riding any turbine runback signal alone has no impact on reactor safety.

Intermediate Range Channels

There are two intermediate range channels which utilize two compensated ionization chambers. Direct current from the ion chambers is transmitted through triaxial cables to transistor logarithmic current amplifiers in the nuclear instrumentation equipment.

The logarithmic amplifier derives a signal proportional to the logarithm of the current as received from the output of the compensated ion chamber. The output of the logarithmic amplifier provides an input to the level bistables for reactor protection purposes and source range cutoff. The bistable trip units are similar to those in the other ranges. The trip outputs can be manually blocked after receiving a permissive signal from the power range channels. On decreasing power, the intermediate range trips for reactor protection are automatically inserted when the power range permissive signal is not present.

Low voltage power supplies contained in each drawer furnish the necessary positive and negative voltages for the channel electronic equipment. Two medium voltage power supplies, one in each channel, furnish compensating voltage to the two compensated ion chambers. The high voltage for the compensated ion chambers is supplied by separate power supplies also located in the intermediate range drawers.

Neutron (log N) flux level indicators are mounted, one each, on the front panel of the intermediate range channel cabinet and on the control board. These indicators are calibrated in terms of ion chamber current (10^{-11} to 10^{-3} amp).

Isolated neutron flux level signals are available for recording and startup rate computation. The startup rate for each channel is indicated at the main control board in terms of decades per minute over the range of –0.5 to 5.0 DPM.

Channel test, high flux level rod stop, and reactor trip signals are alarmed on the main control board annunciator. The latter signal is sent to the Reactor Protection System.

Source Range Channels

There are two source range channels utilizing proportional counter detectors. Neutron flux, as measured in the primary shield area, produces current pluses in the detectors. These preamplified pulses are applied to transistor amplifiers and discriminators located in the racks. Triaxial cable is used for all interconnections from the detector assemblies to the instrumentation in the racks. The preamplifiers are located inside the Reactor Containment.

These channels indicate the source range neutron flux and startup rate. They provide high flux level reactor trip and alarm signals to the Reactor Control and Protection Systems. The reactor trip signal is manually blocked when a permissive signal from the intermediate range is available. These channels are also used at shutdown to provide audible alarms in the Reactor Containment and Control Room of any inadvertent increase in reactivity. An audible count rate signal is used during initial phases of startup and is audible in both the Reactor Containment and Control Room.

Amplifiers are used to obtain a high level signal prior to elimination of noise and gamma pulses by the discriminator. The discriminator output is shaped for use by the log integrator.

The log integrator generates an analog signal proportional to the logarithm of the number of pulses per unit time as received from the output of the previous unit. This unit performs log integration of the pulse rate to determine the count rate, and a linear amplifier amplifies the log integrator output for indication, recording, control, and rate computation through isolation amplifiers.

Each source range channel contains two bistable trip units. Both units trip on high flux level, but one is used during shutdown to alarm reactivity changes and the other provides overpower protection during shutdown and startup. The shutdown alarm unit is blocked manually prior to startup or can serve as a startup alarm. When the input to either unit below its set point, the bistable is in its normal position and assumes a "fully-on" status. When an input from the log amplifier reaches or exceeds the set point, the unit reverses its condition and goes "fully-off." The output of the reactor trip unit controls relays in the Reactor Protection System.

Power supplies furnish the protective and negative voltages for the transistor circuits, the alarm lights, and the adjustable high voltage for the neutron detector.

A test calibration unit can insert selected test or calibration signals into the preamplifier channel input or the log amplifier input. A set of precalibrated level signals are provided to perform channel tests and calibrations. An alarm is registered on the main control board annunciator whenever a channel is being tested or calibrated. A trip bypass switch is also provided to prevent a reactor trip during channel test under certain reactor conditions.

The neutron detector high-voltage cutoff assembly receives a trip signal when a one-out-of-two matrix, controlled by intermediate range channel flux level bistables, and manual block condition are present. The cutoff assembly disconnects the voltage from the source range channel high voltage power supply to prevent operation of the proportional counter outside its design range. High voltage and reactor trip circuits are reactivated automatically when two of the intermediate range signals are below the permissive trip setting.

Mounted on the front panel of the source range channel is a neutron flux level indicator calibrated in terms of count rate level (10^0 to 10^6 cps). Mounted on the control board is a neutron count rate level indicator (100 to 106 cps). Isolated neutron flux signals are available for recording by the Nuclear Instrumentation System recorder and for startup rate computation. The startup rate for each channel is indicted at the main control board in terms of decades per minute over the range of –0.5 to +5.0 DPM. The isolation network for these signals prevents any electrical malfuncton in the external circuitry from affecting the signal being supplied to the flux level bistables. The signals for the channel test, high neutron flux at shutdown, and source range reactor trip are alarmed on the main control board annunciator.

Excore Neutron Flux Monitoring System

The Excore Neutron Flux Monitoring System consists of two redundant trains, each with a Wide range flux detector, locally mounted amplifier and processor, local indications and dedicated penetration feedthroughs and cabling (see Plant Drawing 9321-LL-96553 [Formerly Figure 7.4-4]). Detector sensitivities are illustrated on Figure 7.4-1).

Each of the detectors are fission chambers consisting of two aluminum electrodes electroplated with uranium, insulators and fill gas all included in a titanium assembly. The detectors are located at the 90' and 270' instrument wells and replace the back-up source range detectors that were originally located there. (See Figure 7.4-3)

The amplifiers and microprocessors are located outside the Containment Building in the electrical penetration area in local panels. Redundant trains are powered by redundant instrument bus power supplies. Through isolation devices the Excore Neutron Flux Monitoring System provides the 10 CFR 50, Appendix R, and Reg. Guide 1.97 required shutdown signal. Although both channels provide local and control room (via QSPDS & CFMS) indication, only the detector at the 270' location has the alternate electrical feed capability for Appendix R.

The magnitude of the neutron flux in the reactor core is proportional to the fission power in the reactor. The number of neutron pulses per unit time from the detector is proportional to the magnitude of the neutron flux at the detector and since this magnitude is proportional to the neutron flux in the core, the detector pulse rate is therefore proportional to reactor power.

The number of pulses from the detector is monitored and the mean square value of the variance signal from the detector is measured. This mean square value is proportional to the average rate of neutron pulses. The signal processor takes this signal and processes it into a measure of the logarithm of the countrate, the rate of change of countrate, the logarithm of reactor power and the rate of change of reactor power. It provides analog voltage outputs for each of these signals and also provides the isolated outputs as required.

Auxiliary Equipment

Comparator Channel

The comparator channel compares the four nuclear power signals of the power range channels with one another. A local alarm on the channel is actuated when any two channels deviate from one another by a preset adjustable amount. During full power operation, the comparator serves to sense and annunciate channel failures and/or deviations.

Dropped rod Protection

As backup to the primary protection for the dropped RCC accident, i.e., the rod bottom signal, independent detection is provided by means of the out-of-core power range nuclear channels. The dropped-rod sensing unit contains a difference amplifier, which compares the instantaneous nuclear power signal with an adjustable power lag signal and responds with a trip signal to the bistable amplifier when the difference exceeds a preset adjustable amount. Above a given power level, the signal blocks automatic rod withdrawal and initiates protective action in the form of a turbine load cutback. No credit is taken in the dropped rod accident analysis for turbine runback.

Audio Count Rate Channel

The auto count rate channel provides audible source range information during refueling operations in both the Control Room and the Reactor Containment. In addition, this channel signal is fed to a scaler-timer assembly which produces a visual display of the count rate for an adjustable sampling period.

Recorders

One large, two-pen strip chart recorder is mounted on the main control board for recording the complete range of the source and intermediate channels. It is also possible to record any two power range channels as linear signals. Variable chart speeds have been provided.

Switching of inputs to the recorders does not cause any spurious signals that would initiate false alarms or reactor trips.

Two two-pen recorders are provided to record the flux level from each of the four nuclear power range quadrants.

Power Supply

The Nuclear Instrumentation System is powered by four 120 volts AC independent vital bus circuits. (See Chapter 8)

7.4.3 System Evaluation

Loss of Power

The nuclear instrumentation draws its primary power from vital instrument buses discussed in Chapter 8.

Loss of nuclear instrumentation power would result in the initiation of all reactor trips associated with the channel power failure. In addition, all trips which were blocked prior to loss would be unblocked and initiated.

Reliability and Redundancy

The requirements established for the reactor protective system apply to the nuclear instrumentation. All channel functions are independent of every other channel.

Safety Factor

The relations of the power range channels to the Reactor Protective System has been described in Section 7.2. To maintain the desired accuracy in trip action, the total error from drift in the power range channels is held to ±1 percent of full power. Routine tests and recalibration ensure that this degree of deviation is not exceeded. Bistable trip set points of the power range channels are also held to an accuracy of ±1 percent of full power. The accuracy and stability of the equipment were verified by vendor tests.

Overpower Trip Set Point

The overpower trip set point for the Indian Point 3 Reactor is 109%. This trip set point was selected to provide adequate assurance that spurious reactor trips would not occur during normal operation. Table 7.4-1 lists the factors which make up the maximum overpower level of 118% based upon a trip set point of 109%.

TABLE 7.4-1

INSTRUMENTATION DRIFT AND CALORIMETRIC ERRORS
NUCLEAR OVERPOWER TRIP CHANNEL

	Set Point and Error Allowances: (% of rated power)	Estimated Instrument Errors: (% of rated power)
Nominal Set Point	109	-
Calorimetric Error	2	1.55
Axial power distribution effects on total ion chamber current	5	3
Instrumentation channel drift and set point reproductibility	2	1.0
Maximum overpower trip point assuming all individual errors are simultaneously in the most adverse direction	118	-

7.5 PROCESS INSTRUMENTATION

7.5.1 Design Bases

The non-nuclear process instrumentation measures temperatures, pressures, flows, and levels in the Reactor Coolant System, Steam System, Reactor Containment and Auxiliary Systems. Process variables required on a continuous basis for the startup, operation, and shutdown of the unit are indicated, recorded and controlled from the Control Room. The quantity and types of process instrumentation provided ensure safe and orderly operation of all systems and processes over the full operating range of the plant.

Certain controls which require a minimum of operator attention, or are only in use intermittently, are located on local control panels near the equipment to be controlled. Monitoring of the alarms of such control systems are provided in the Control Room.

Certain process variable indications for normal operation and post accident conditions are made available in the Control Room and the emergency response facilities through the Critical Function Monitoring System (CFMS).

7.5.2 System Design

Much of the process instrumentation provide din the plant has been described in the Reactor Control System, the Reactor Protection System and the Nuclear Instrumentation System descriptions (see Sections 7.2, 7.3 and 7.4, respectively). The most important instrumentation used to monitor and control the plant have been described in the above systems descriptions. The remaining portion of the process instrumentation is generally shown on the respective systems process flow diagrams.

Condensate pots and wet legs are used to prevent process temperatures from actually reaching the transmitters.

Reactor Vessel Level Indicating System (RVLIS)

The Reactor Vessel Level Indicating System (RVLIS) provides a means to monitor the water level in the reactor vessel during a postulated accident. It is designed to function under all normal, abnormal, accident and post-accident conditions concurrent with seismic events. The RVLIS consists of two redundant trains, with redundant power supplies, which automatically compensate for variations in fluid density as well as for the effects of reactor coolant pump operation.

The level instrumentation is divided into the full range (Δ_{PF}) and the dynamic range (Δ_{PF}) in order to measure level under all conditions. The full range gives level indication from the bottom of the reactor vessel to the top of the reactor head during natural circulation conditions. The dynamic range gives indication of reactor vessel liquid level for any combination of running RCP's. Comparison of indicated d/p against an algorithm derived ΔP gives a relative void content of the coolant in the core. (See Figure 7.5-2)

The RVLIS utilizes RCS penetrations to manual isolation valves. At the valves are sealed capillary impulse lines (two at the reactor head and two at the seal table) which transmit pressure measurements to d/p transmitters located outside the Containment Building in the in

the Primary Auxiliary Building. The capillary impulse lines are sealed at the RCS end and at the penetrations (inside Containment) with sensor bellows which serve as hydraulic couplers. The impulse lines extend through the Containment wall to hydraulic isolators which seal and isolate the lines as well as provide hydraulic coupling to capillary tubes going to the d/p transmitters. Inside the Containment Building, strap-on RTD's are utilized for vertical runs of impulse lines to correct the reference leg density contributions to the d/p measurement. (See Figure 7.5-2)

Engineered Safety Features

The following instrumentation ensures coverage of the effective operation of the engineered safety features:

Containment Pressure

The containment pressure is transmitted to the main control board for post accident monitoring. Six transmitters, two in each of three safety channels, are installed outside the containment to prevent potential missile damage. The pressure is indicated (all six measurement loops) on the main control board; the range is –5 psig to 75 psig.

The six measurement loops, monitoring containment pressure, reflect the effectiveness of engineered safety features.

Separate from the above, a continuous record of containment pressure is provided in a separate recorder panel in the Control Room. Two redundant and separately channeled safety related, Containment Building pressure measurements are transmitted to and recorded in the Control Room; their range is –5 psig to +200 psig. Each pressure measurement loop consists of a pressure transmitter, a pressure recorder and the necessary signal conditioning equipment, including a power supply, located in the Control Room. Each measurement loop is powered from a separate safety related 118 volts AC instrument bus. (See Section 5.5)

Containment Building Hydrogen Concentration

Indication of hydrogen in the Containment Building during and after a postulated accident is available from redundant sample conditioners and analyzers. The concentration is continually recorded by 2 recorders located in the Control Room.

Containment Building and Sump Water Level

There are measuring loops for monitoring water level in the Containment Sump, Recirculation Sump and the Containment Building. Each loop consists of a sensor and transmitter located in the Containment Building and a power supply and recorder in the Control Room.

In addition, to alert the operator in the event of a flooding incident, a reactor pit water level alarm provides indication in the Control Room; and a water level sensing probe and remote control unit provide containment sump overflow indication to the Control Room.

Refueling Water Storage Tank Level

Two redundant channels indicate that Safety Injection and Containment Spray Systems have removed water from the storage tank. One level indication and two low level alarms are transmitted from the tank to the control board.

Safety Injection Pumps Discharge Pressure

These channels show that the safety injection pumps are operating. The transmitters are outside the Containment.

Safety Injection System Flows

Flow indication is provided to the control board for the high and low head injection lines, the recirculation phase containment spray lines, and the spray additive rank outlet line.

Pump Energization

All pump motor power feed breakers indicate that they have closed by energizing indicatng lights on the control board.

Valve Position

All engineered safety features valves have position indication on the control board to show proper positioning of the valves. Air operated and solenoid operated valves are selected so as to move in a preferred direction on the loss of air or power. Motor-operated valves remain in the position they held at the time of loss of power to the motor.

Residual Heat Exchangers

Individual exit flows are indicated, plus combined inlet temperature and individual exit temperatures are recorded, on the control board to monitor operation of the residual heat exchangers.

Service Water

Individual service water pump flows are monitored through the use of an annubar flow measurement system. This system provides flow indication at the service water pump location.

Air Coolers

Local flow indication is provided outside containment for service water flow to each cooling unit. Abnormal flow alarms are provided in the Control Room. Service water common inlet temperatures, and all outlet temperatures are displayed at the critical function monitoring system (CFMS). A Control Room alarm is actuated if the flow is low coincident with a safety injection signal. The transmitters are outside the Reactor Containment. In addition, the exit flow is monitored for radiation and alarmed in the Control Room if high radiation should occur. This is a common monitor and the faulty cooler can be located by manually blocking the flow to each unit in turn with locally operated valves.

Alarms

Visual and audible alarms are provided to call attention to abnormal conditions. The alarms are of the individual acknowledgment type; that is, the operator must recognize and silence the audible alarm for each alarm point. For most control systems, the sensing device and circuits for the alarms are independent, or isolated from, the control devices.

In addition to the above, the following local instrumentation is available:

a) Containment spray test lines total flow
b) Safety injection test line pressure and flow

Monitoring Systems

A Safety Parameter Display System (SPDS) is provided to the Control Room which continuously displays information from which plant status can be assessed. Information on the following functions is provided:

a) Reactivity Control
b) Reactor core cooling and heat removal from the primary system
c) Reactor coolant system integrity
d) Radioactivity control
e) Containment conditions

The SPDS consists of the Critical Functions Monitoring System (CFMS) and the Qualified Safety Parameters Display System (QSPDS). The CFMS displays and alarms of critical safety functions (set of actions, which preserve integrity of one or more physical barriers against radiation) are indicated in the Control Room (CR) and the three emergency response facilities Technical Support Center (TSC), Emergency Operations Facility (EOF) and Alternate Emergency Operations Facility (AEOF). The CFMS is a redundant computer system not designed to seismic and electrical class 1E criteria. The QSPDS is a backup display system to the CFMS that is qualified to seismic and electrical class 1E standards.

The QSPDS design and display is based on NRC Regulatory Guide 1.97 criteria. The CFMS provides for historical data storage and retrieval capability (HDSR). The HDSR system will record, store, recall and display historical information either as graphs and trends or printed logs.

The CFMS/QSPDS receive signals from various plant equipment. The CFMS receives signals from safety related and non-safety related sources, and adequate electrical separation is maintained by use of fiber optic links.

In order to comply with the requirements of Regulatory Guide 1.97, additions to the original plant design parameters were made. Transmitters monitoring many process variables were installed and the CFMS is utilized to alarm and display these parameters. In some cases local indicators are also provided to facilitate local operation needs. Besides additions, replacement of existing components were made to upgrade them to meet the requirements.

7.5.3 System Evaluation

Redundant instrumentation has been provided for all inputs to the protective system and vital control circuits.

Where wide process variable ranges and precise control are required, both wide range and narrow range instrumentation is provided.

All electrical and electronic instrumentation required for safe and reliable operation is supplied from four redundant instrumentation buses.

7.5.4 Instrument Required

Table 7.5-1 identifies the instruments used to demonstrate compliance with NRC Regulatory Guide 1.97. Exemptions to compliance are noted in the table.

The Technical Specifications establish required actions and completion times for Regulatory Guide 1.97 Type A and Category 1 instrument channels.

In addition, inoperability of the following associated recorders is limited to 14 days: Containment Pressure, Containment Water Level, Recirculation Sump Water Level, Containment Hydrogen Monitor, Steam Generator Water level (Wide Range), RCS Pressure (Wide Range), Cold Leg Temperature (Wide Range), Hot Leg Temperature (Wide Range), Pressurizer Water Level, RCS Subcooling Monitor.

Surveillance requirements for Regulatory Guide 1.97 Type A and Category 1 instruments are established in the Technical Specifications. In addition, a Channel Operational Test is required, as follows, for alarms that are associated with Type A and Category 1 instruments, but which have no Regulatory Guide function:

- Main Steam Line Radiation (R62), Quarterly
- Gross Failed Fuel Detector (R63), Quarterly
- Containment Hydrogen Monitor, Monthly

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
101A	A1	Primary Coolant	Pressure, Reactor Coolant System, Loop 1	P402	J
101B	A1	Primary Coolant	Pressure, Reactor Coolant System, Loop 4	P403	J
102A	A1	Primary Coolant	Temperature, Hot Leg Loop No. 1	T413A	P
102B	A1	Primary Coolant	Temperature, Hot Leg Loop No. 2	T423A	P
102C	A1	Primary Coolant	Temperature, Hot Leg Loop No. 3	T433A	P
102D	A1	Primary Coolant	Temperature, Hot Leg Loop No. 4	T443A	P
103A	A1	Primary Coolant	Temperature, Cold Leg Loop No. 1	T413B	P
103B	A1	Primary Coolant	Temperature, Cold Leg Loop No. 2	T423B	P
103C	A1	Primary Coolant	Temperature, Cold Leg Loop No. 3	T433B	P
103D	A1	Primary Coolant	Temperature, Cold Leg Loop No. 4	T443B	P
104A	A1	Steam Generator 31	Level, Wide Range	L417D	K
104B	A1	Steam Generator 31	Level, Narrow Range	L417A	K
104C	A1	Steam Generator 31	Level, Narrow Range	L417B	K
104D	A1	Steam Generator 31	Level, Narrow Range	L417C	K
104E	A1	Steam Generator 32	Level, Wide Range	L427D	K
104F	A1	Steam Generator 32	Level, Narrow Range	L427A	K
104G	A1	Steam Generator 32	Level, Narrow Range	L427B	K
104H	A1	Steam Generator 32	Level, Narrow Range	L427C	K
104I	A1	Steam Generator 33	Level, Wide Range	L437D	K
104J	A1	Steam Generator 33	Level, Narrow Range	L437A	K
104K	A1	Steam Generator 33	Level, Narrow Range	L437B	K
104L	A1	Steam Generator 33	Level, Narrow Range	L437C	K
104M	A1	Steam Generator 34	Level, Wide Range	L447D	K
104N	A1	Steam Generator 34	Level, Narrow Range	L447A	K
104O	A1	Steam Generator 34	Level, Narrow Range	L447B	K
104P	A1	Steam Generator 34	Level, Narrow Range	L447C	K
105A	A1	Pressurizer	Level, Channel I	L459	
105B	A1	Pressurizer	Level, Channel II	L460	
105C	A1	Pressurizer	Level, Channel III	L461	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
106B	A1	Containment	Wide Range Pressure, Channel I	P1421	O
106C	A1	Containment	Wide Range Pressure, Channel II	P1422	O
107A	A1	Steam Generator 31	Pressure, Channel I	P419A	
107B	A1	Steam Generator 31	Pressure, Channel II	P419B	
107C	A1	Steam Generator 31	Pressure, Channel IV	P419C	
107D	A1	Steam Generator 32	Pressure, Channel I	P429A	
107E	A1	Steam Generator 32	Pressure, Channel II	P429B	
107F	A1	Steam Generator 32	Pressure, Channel IV	P429C	
107G	A1	Steam Generator 33	Pressure, Channel I	P439A	
107H	A1	Steam Generator 33	Pressure, Channel II	P439B	
107I	A1	Steam Generator 33	Pressure, Channel IV	P439C	
107J	A1	Steam Generator 34	Pressure, Channel I	P449A	
107K	A1	Steam Generator 34	Pressure, Channel II	P449B	
107L	A1	Steam Generator 34	Pressure, Channel IV	P449C	
108A	A1	Refueling Water Storage Tank	Level, Alarm	L920	N
108B	A1	Refueling Water Storage Tank	Level, Alarm	L921	N
109A	A1	Containment	Water Level	L1253	L
109B	A1	Containment	Water Level	L1254	L
111A	A1	Containment	Radiation, Area, High Range	R25	
111B	A1	Containment	Radiation, Area, High Range	R26	
112A	A1	Secondary Cooling	Radiation, Main Steam	R62	SS
113A	A1	Primary Coolant	Temperature, Core Exit	CE-T-***	TT
114A	A1	Condensate Storage Tank Level	Water Level	L1128	
114B	A1	Condensate Storage Tank Level	Water Level	L1128A	
115A	A1	Primary Coolant	Temperature, Degrees of RCS Subcooling	QSPDS-A	M

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
115B	A1	Primary Coolant	Temperature, Degrees of RCS Subcooling	QSPDS-B	M
201A	B1	Neutron Flux Excore	Radiation, Intermediate Range Channel I	N38	
201B	B1	Neutron Flux Excore	Radiation, Intermediate Range Channel II	N39	
202A	B3	Control Rods	Position	N/A	
203A	B3	Primary Coolant	Sampling, Soluble Boron Concentration	N/A	Grab Sample
204A	B3	Primary Coolant	Temperature, Cold Leg, Loop No. 1	T413B	P
204B	B3	Primary Coolant	Temperature, Cold Leg, Loop No. 2	T423B	P
204C	B3	Primary Coolant	Temperature, Cold Leg, Loop No. 3	T433B	P
204D	B3	Primary Coolant	Temperature, Cold Leg. Loop No. 4	T433B	P
205A	B1	Primary Coolant	Temperature, Hot Leg, Loop No. 1	T413A	P
205B	B1	Primary Coolant	Temperature, Hot Leg, Loop No. 2	T423A	P
205C	B1	Primary Coolant	Temperature, Hot Leg, Loop No. 3	T433A	P
205D	B1	Primary Coolant	Temperature, Hot Leg, Loop No. 4	T443A	P
206A	B1	Primary Coolant	Temperature, Cold Leg, Loop No. 1	T413B	P
206B	B1	Primary Coolant	Temperature, Cold Leg, Loop No. 2	T423B	P
206C	B1	Primary Coolant	Temperature, Cold Leg, Loop No. 3	T433B	P
206D	B1	Primary Coolant	Temperature, Cold Leg, Loop No. 4	T443B	P
207A	B1	Primary Coolant	Pressure, Reactor Coolant System, Loop 1	P402	J
207B	B1	Primary Coolant	Pressure, Reactor Coolant System, Loop 4	P403	J
208A	B3	Primary Coolant	Temperature, Core Exit	CE-T-***	TT
209A	B1	Primary Coolant	Level, Reactor	RVLIS TR-A & B	
210A	B2	Primary Coolant	Temperature, Degrees of Subcooling	QSPDS-A	
210B	B2	Primary Coolant	Temperature, Degrees of Subcooling	QSPDS-B	
211A	B1	Primary Coolant	Pressure, Reactor Coolant System, Loop 1	P402	J
211B	B1	Primary Coolant	Pressure, Reactor Coolant System, Loop 4	P403	J
212C	B2	Containment	Level, Containment Sump Water Channel I	L1255	L
212D	B2	Containment	Level, Containment Sump Water Channel II	L1256	L
212E	B1	Containment	Level, Wide Range Channel I	L1253	L

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	**TYPE CAT**	**VARIABLE ONE**	**VARIABLE TWO**	**INST LOOP**	**NOTES**
212F	B1	Containment	Level, Wide Range Channel II	L1254	L
212I	B2	Containment	Level, Wide Range Redundant Channel: Recirculation Sump Level-Channel I	L1251	L
212J	B2	Containment	Level, Wide Range Redundant Channel: Recirculation Sump Level-Channel II	L1252	L
213B	B1	Containment	Pressure, Channel I	P1421	O
213C	B1	Containment	Pressure, Channel II	P1422	O
214A	B1	Containment	Position, Isolation valve	N/A	Y
215B	B1	Containment	Pressure, Channel I	P1421	O
215C	B1	Containment	Pressure, Channel II	P1422	O
301A	C1	Primary Coolant	Temperature, Core Exit	CE-T-***	TT
302A	C1	Primary Coolant	Radiation, Radioactivity Concentration	R-63A&B	
303A	C1	Primary Coolant	Radiation, Gamma Spectrum	N/A	W
304A	C1	Primary Coolant	Pressure, Reactor Coolant System Loop 4	P402	J
304B	C1	Primary Coolant	Pressure, Reactor Coolant System Loop 1	P403	J
305B	C1	Containment	Pressure, Channel I	P1421	O
305C	C1	Containment	Pressure, Channel II	P1422	O
306C	C2	Containment	Level, Containment Sump Water Channel I	L1255	L
306D	C2	Containment	Level, Containment Sump Water Channel II	L1256	L
306E	C1	Containment	Level, Wide Range Channel I	L1253	L
306F	C1	Containment	Level, Wide Range Channel II	L1254	L
306I	C1	Containment	Level, Wide Range Redundant Channel: Recirculation Sump Level-Channel I	L1251	L
306J	C1	Containment	Level, Wide Range Redundant Channel: Recirculation Sump Level-Channel II	L1252	L
307A	C3	Containment	Radiation, Area	R25	
307B	C3	Containment	Radiation, Area	R26	
308A	C3	Cond Air Removal Sys	Radiation, Effluent Noble Gas	R15	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
		Exhaust			
309A	C1	Primary Coolant	Pressure, Reactor Coolant System, Loop 1	P402	J
309B	C1	Primary Coolant	Pressure, Reactor Coolant System, Loop 4	P403	J
310B	C1	Containment Air	Sampling, Hydrogen Concentration Channel I	HCMC-A	
310C	C1	Containment Air	Sampling, Hydrogen Concentration Channel II	HCMC-B	
311B	C1	Containment	Pressure, Channel I	P1421	O
311C	C1	Containment	Pressure, Channel II	P1422	O
312A	C2	Containment	Radiation, Effluent, Noble Gas, Penetration Area	R12	AA
314B	C2	Penetration Area	Radiation, Area, Electrical Tunnel In Area of Electrical Penetration	N/A	BB
314C	C2	Penetration Area	Radiation, Area, 83' Personnel Airlock Area	N/A	BB
314D	C2	Penetration Area	Radiation, Area, Containment Purge Valve Area Between Containment & Fan House	N/A	BB
314E	C2	Penetration Area	Radiation, Area, 95' Personnel & Equipment Hatch Area	N/A	BB
314F	C2	Penetration Area	Radiation, Area, Fuel Transfer Area Between Containment & Fuel Storage Buildings	N/A	BB
314G	C2	Fuel Storage Building	Radiation, Area, Penetration Area, In Area of Fuel Transfer Tube	R5	BB
314H	C2	PAB 34' FL EL	Radiation Area, Piping Tunnel In Area of Containment Sump Drain Pent	N/A	BB
314J	C2	PAB 54' FL EL	Radiation, Area, Piping Tunnel in Area of Piping Penetrations	N/A	BB
401A	D2	Residual Heat Removal	Flow Rate, Header 31	F638	
401B	D2	Residual Heat Removal	Flow Rate, Header 32	F640	
401C	D2	Residual Heat Removal	Flow Rate, Loop 4	FT946A	
401D	D2	Residual Heat Removal	Flow Rate, Loop 3	FT946B	
401E	D2	Residual Heat Removal	Flow Rate, Loop 2	FT946C	
401F	D2	Residual Heat Removal	Flow Rate, Loop 1	FT946D	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
402A	D2	Residual Heat Removal	Temperature, Heat Exchanger 31 Outlet	T639	
402B	D2	Residual Heat Removal	Temperature, Heat Exchanger 32 Outlet	T641	
403A	D2	Safety Injection	Level, Accumulator Tank 31	L934A	Z
304B	D2	Safety Injection	Level, Accumulator Tank 32	L934B	Z
403C	D2	Safety Injection	Level, Accumulator Tank 33	L934C	Z
403D	D2	Safety Injection	Level, Accumulator Tank 34	L934D	Z
403E	D2	Safety Injection	Pressure, Accumulator Tank 31	P937A	Z
403F	D2	Safety Injection	Pressure, Accumulator Tank 32	P937B	Z
403G	D2	Safety Injection	Pressure, Accumulator Tank 33	P937C	Z
403H	D2	Safety Injection	Pressure, Accumulator Tank 34	P937D	Z
404A	D2	Safety Injection	Pressure, Accumulator Tank 31 Isolation Valve 894A	N/A	HH
404B	D2	Safety Injection	Pressure, Accumulator Tank 32 Isolation Valve 894B	N/A	HH
404C	D2	Safety Injection	Pressure, Accumulator Tank 33 Isolation Valve 894C	N/A	HH
404D	D2	Safety Injection	Pressure, Accumulator Tank 34 Isolation Valve 894D	N/A	HH
405A	D2	Safety Injection	Flow, Boric Acid Charging	F128	H
406A	D2	Safety Injection	Flow, High Head, Cold Leg Loop I	F926	
406B	D2	Safety Injection	Flow, High Head, Cold Leg Loop I	F924A	
406C	D2	Safety Injection	Flow, High Head, Cold Leg Loop 2	F981	
406D	D2	Safety Injection	Flow, High Speed, Cold Leg Loop 2	F925	
406E	D2	Safety Injection	Flow, High Speed, Cold Leg Loop 3	F980	
406F	D2	Safety Injection	Flow, High Speed, Cold Leg Loop 3	F926A	
406G	D2	Safety Injection	Flow, High Speed, Cold Leg Loop 4	F982	
406H	D2	Safety Injection	Flow, High Speed, Cold Leg Loop 4	F927	
407A	D2	Safety Injection	Flow, Low Head	F638	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
407B	D2	Safety Injection	Flow, Low Head	F640	
408A	D2	Safety Injection	Level, Refueling Water Storage Tank	L920	
409A	D3	Primary Coolant	Status, Reactor Coolant Pump 31	N/A	
409B	D3	Primary Coolant	Status, Reactor Coolant Pump 32	N/A	
409C	D3	Primary Coolant	Status, Reactor Coolant Pump 33	N/A	
409D	D3	Primary Coolant	Status, Reactor Coolant Pump 34	N/A	
410A	D2	Primary Coolant	Position, Safety Relief Valve, Power Operated Relief Valve 455C	N/A	Acoustical Monitor At Valve
410B	D2	Primary Coolant	Position, Safety Relief Valve, Power Operated Relief Valve 456	N/A	Acoustical Monitor At Valve
410C	D2	Primary Coolant	Position, Safety Relief Valve, ASME Code Safety Valve 464	N/A	Acoustical Monitor At Valve
410D	D2	Primary Coolant	Position, Safety Relief Valve, ASME Code Safety Valve 466	N/A	Acoustical Monitor At Valve
410E	D2	Primary Coolant	Position, Safety Relief Valve, ASME Code Safety Valve 468	N/A	Acoustical Monitor At Valve
411A	D1	Primary Coolant	Level, Pressurizer Channel I	L459	
411B	D1	Primary Coolant	Level, Pressurizer Channel II	L460	
411C	D1	Primary Coolant	Level, Pressurizer Channel III	L461	
412A	D2	Primary Coolant	Status, Pressurizer Heater – Control Group	N/A	U
412B	D2	Primary Coolant	Status, Pressurizer Heater – Back-up Group 31	N/A	U
412C	D2	Primary Coolant	Status, Pressurizer Heater – Back-up Group 32	N/A	U
412D	D2	Primary Coolant	Status, Pressurizer Heater – Back-up Group 33	N/A	U
413A	D3	Primary Coolant	Level, Pressurizer Relief Tank 31	L470	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
414A	D3	Primary Coolant	Temperature, Pressurizer Relief Tank 31	T471	
415A	D3	Primary Coolant	Pressure, Pressurizer Relief Tank 31	P472	
416A	D1	Secondary Cooling	Level, Steam Generator 31	L417D	K
416B	D1	Secondary Cooling	Level, Steam Generator 32	L427D	K
416C	D1	Secondary Cooling	Level, Steam Generator 33	L437D	K
416D	D1	Secondary Cooling	Level, Steam Generator 34	L447D	K
417A	D2	Secondary Cooling	Pressure, Steam Generator 31, Channel I	P419A	
417B	D2	Secondary Cooling	Pressure, Steam Generator 32, Channel I	P429A	
417C	D2	Secondary Cooling	Pressure, Steam Generator 33, Channel I	P439A	
417D	D2	Secondary Cooling	Pressure, Steam Generator 34, Channel I	P449A	
418A	D2	Secondary Cooling	Flow, Main Steam From Steam Generator 31	F419A&B	
418B	D2	Secondary Cooling	Flow, Main Steam From Steam Generator 32	F429A&B	
418C	D2	Secondary Cooling	Flow, Main steam From Steam Generator 33	F439A&B	
418D	D2	Secondary Cooling	Flow, Main Steam From Steam Generator 34	F449A&B	
419A	D3	Secondary Cooling	Flow, Main Feedwater To Steam Generator 31	F418A&B	
419B	D3	Secondary Cooling	Flow, Main Feedwater To Steam Generator 32	F428A&B	
419C	D3	Secondary Cooling	Flow, Main Feedwater To Steam Generator 33	F438A&B	
419D	D3	Secondary Cooling	Flow, Main Feedwater To Steam Generator 34	F448A&B	
420A	D2	Secondary Cooling	Flow, Auxiliary Feedwater To Steam Generator 31	F1200R	
420B	D2	Secondary Cooling	Flow, Auxiliary Feedwater To Steam Generator 32	F1201R	
420C	D2	Secondary Cooling	Flow, Auxiliary Feedwater To Steam Generator 33	F1202R	
420D	D2	Secondary Cooling	Flow, Auxiliary Feedwater To Steam Generator 34	F1203R	
421A	D1	Secondary Cooling	Level, Condensate Storage Tank Water	L1128	G
421B	D1	Secondary Cooling	Level, Condensate Storage Tank Water	L1128A	G
422A	D2	Containment	Flow, Spray From Residual Heat Removal Heat Exchanger 31	F945B	II
422B	D2	Containment	Flow, Spray From Residual Heat Removal Heat Exchanger 32	F945A	II
423A	D2	Containment	Flow, Heat Removal By System-Service Water	F1121	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
			RCFC 31		
423B	D2	Containment	Flow, Heat Removal By system-Service Water RCFC 32	F1122	
423C	D2	Containment	Flow, Heat Removal By System-Service Water RCFC 33	F1123	
423D	D2	Containment	Flow, Heat Removal By System-Service Water RECF 34	F1124	
423E	D2	Containment	Flow, Heat Removal By System-Service Water RCFC 35	F1125	
423F	D2	Containment	Temperature, Heat Removal By System-Service Water Diff RCFC 31	T-1415-1	
423G	D2	Containment	Temperature, Heat Removal By System-Service Water Diff RCFC 32	T-1415-2	
423H	D2	Containment	Temperature, Heat Removal By System-Service Water Diff RCFC 33	T-1415-3	
423J	D2	Containment	Temperature, Heat Removal By-System-Service Water Diff RCFC 34	T-1415-4	
423K	D2	Containment	Temperature, Heat Removal By System-Service Water Diff RCFC 35	T-1415-5	
424A	D2	Containment	Temperature, Atmosphere	T1203	
425A	D2	Containment	Temperature, Sump Water	NONE	I
426A	D2	Chemical & Volume Control	Flow, Make-up In	F128	
427A	D2	Chemical & Volume Control	Flow, Letdown Out	F134	B
428A	D2	Chemical & Volume Control	Level, Volume Control Tank	L112	C
429A	D2	Component Cooling	Temperature, Component Cooling Heat Exchanger 31 Output	T602A	D

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
429B	D2	Component Cooling	Temperature, Component Cooling Heat Exchanger 32 Output	T602B	D
430A	D2	Component Cooling	Flow, Component Cooling Heat Exchanger 31 Output	F601A	E
430B	D2	Component Cooling	Flow, Component Cooling Heat Exchanger 32 Output	F601B	E
431A	D3	Radwaste	Level, High-Level Radioactive Waste Hold-up Tank 31	L1001	
431B	D3	Radwaste	Level, High-Level Radioactive Waste Hold-up Tank 32 (3HBT01A)	L168	JJ
431C	D3	Radwaste	Level, High-Level Radioactive Waste Hold-up Tank 33 (3HBT01B)	L170	JJ
432A	D3	Radwaste	Pressure, Large Radioactive Gas Decay Tank 31	P1036	KK
432B	D3	Radwaste	Pressure, Large Radioactive Gas Decay Tank 32	P1037	KK
432C	D3	Radwaste	Pressure, Large Radioactive Gas Decay Tank 33	P1038	KK
432D	D3	Radwaste	Pressure, Large Radioactive Gas Decay Tank 34	P1039	KK
432E	D3	Radwaste	Pressure, Small Radioactive Gas Decay Tank 31	P1052	KK
432F	D3	Radwaste	Pressure, Small Radioactive Gas Decay Tank 32	P1053	KK
432G	D3	Radwaste	Pressure, Small Radioactive Gas Decay Tank 33	P1054	KK
432H	D3	Radwaste	Pressure, Small Radioactive Gas Decay Tank 34	P1055	KK
432J	D3	Radwaste	Pressure, Small Radioactive Gas Decay Tank 35	P1056	KK
432K	D3	Radwaste	Pressure, Small Radioactive Gas Decay Tank 36	P1057	KK
433A	D2	Ventilation	Position, Reactor Containment Fan Cooler 31 Damper A & B	N/A	GG
433B	D2	Ventilation	Position, Reactor Containment Fan Cooler 31 Damper A & B	N/A	GG
433C	D2	Ventilation	Position, Reactor Containment Fan Cooler 31 Damper D & Blow-in Door	N/A	GG
433D	D2	Ventilation	Position, Reactor Containment Fan Cooler 32	N/A	GG

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
			Damper A & B		
433E	D2	Ventilation	Position, Containment Fan Cooler 32 Damper C	N/A	GG
433F	D2	Ventilation	Position, Reactor Containment Fan Cooler 32 Damper D & Blow-in Door	N/A	GG
433G	D2	Ventilation	Position, Reactor Containment Fan Cooler 33 Damper A & B	N/A	GG
433H	D2	Ventilation	Position, Reactor Containment Fan Cooler 33 Damper C	N/A	GG
433J	D2	Ventilation	Position, Reactor Containment Fan Cooler 33 Damper D & Blow-in Door	N/A	GG
433K	D2	Ventilation	Position, Reactor Containment Fan Cooler 34 Damper A & B	N/A	GG
433L	D2	Ventilation	Position, Reactor Containment Fan Cooler 34 Damper C	N/A	GG
433M	D2	Ventilation	Position, Reactor Containment Fan cooler 34 Damper D & Blow-in Door	N/A	GG
433N	D2	Ventilation	Position, Reactor Containment Fan Cooler 35 Damper A & B	N/A	GG
433P	D2	Ventilation	Position, Reactor Containment Fan Cooler 35 Damper C	N/A	GG
433R	D2	Ventilation	Position, Reactor Containment Fan Cooler 35 Damper D & Blow-in Door	N/A	GG
433S	D2	Ventilation	Position, Fuel Storage Building Forced Air Unit 31 Emergency Damper	N/A	GG
433T	D2	Ventilation	Position, Fuel Storage Building Forced Air Unit 32 Emergency Damper	N/A	GG
433U	D2	Ventilation	Position, Fuel Storage Building Normal Airflow Top Damper	N/A	GG
433V	D2	Ventilation	Position, Fuel Storage Building Normal Airflow Bottom Damper	N/A	GG

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
433W	D2	Ventilation	Position, Fuel Storage Building Emergency Airflow Filter Intake Damper	N/A	GG
433X	D2	Ventilation	Position, Fuel Storage Building Emergency Airflow Filter Exhaust Damper	N/A	GG
433Y	D2	Ventilation	Position, Primary Auxiliary Building Exhaust Charcoal Damper – Face	N/A	GG
433Z	D2	Ventilation	Position, Primary Auxiliary Building Exhaust Charcoal Damper – Bypass	N/A	GG
434A	D2	Emergency Power	Current, AC Bus 31	N/A	
434B	D2	Emergency Power	Current, AC Bus 32	N/A	
434C	D2	Emergency Power	Current, AC Bus 33	N/A	
434D	D2	Emergency Power	Current, AC Bus 34	N/A	
434E	D2	Emergency Power	Voltage, AC Bus 31	N/A	
434F	D2	Emergency Power	Voltage, AC Bus 32	N/A	
434G	D2	Emergency Power	Voltage, AC Bus 33	N/A	
434H	D2	Emergency Power	Voltage, AC Bus 34	N/A	
434I	D2	Emergency Power	Current, DC Bus 31	N/A	F
434J	D2	Emergency Power	Current, DC Bus 32	N/A	F
434K	D2	Emergency Power	Current, DC Bus 33	N/A	F
434L	D2	Emergency Power	Current, DC Bus 34	N/A	F
434M	D2	Emergency Power	Voltage, DC Bus 31	N/A	
434N	D2	Emergency Power	Voltage, DC Bus 32	N/A	
434O	D2	Emergency Power	Voltage, DC Bus 33	N/A	
434P	D2	Emergency Power	Voltage, DC Bus 34	N/A	
434Q	D2	Emergency Power	Current, Diesel 31	N/A	
434R	D2	Emergency Power	Current, Diesel 32	N/A	
434S	D2	Emergency Power	Current, Diesel 33	N/A	
434T	D2	Emergency Power	Voltage, Diesel 31	N/A	
434U	D2	Emergency Power	Voltage, Diesel 32	N/A	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	**TYPE CAT**	**VARIABLE ONE**	**VARIABLE TWO**	**INST LOOP**	**NOTES**
434V	D2	Emergency Power	Voltage, Diesel 33	N/A	
434W	D2	Emergency Air Supply	Pressure, Instrument Air Receiver Tank	P1207	
434X	D2	Emergency Air Supply	Pressure, Diesel 31 Starting Air Receiver Tank	N/A	
434Y	D2	Emergency Air Supply	Pressure, Diesel 32 Starting Air Receiver Tank	N/A	
434Z	D2	Emergency Air Supply	Pressure, Diesel 33 Starting Air Receiver Tank	N/A	
501A	E1	Containment	Radiation, Area, High Range	R25	
501B	E1	Containment	Radiation, Area, High Range	R26	
502A	E3	Central Control Room	Radiation, Area	R1	MM,CC,X
502B	E3	PAB 80'	Radiation, Area, Charging Pump Room	R4	DD
502C	E3	Fuel Storage Building	Radiation, Area	R5	
502D	E3	PAB 55'	Radiation, Area, Sampling Room (North Wall)	R6	X
502E	E2	Containment	Radiation, Area, (AT Seal Table) In-core Instrument Room	R7	X, DD
502F	E2	PAB 55'	Radiation, Area, Drumming Station	R8	X, DD
502G	E2	Aux Boiler Feed Pump Bldg	Radiation, Area, (West Wall Opposite Main Steam Penetrations 31 & 32)	NONE	X
502H	E2	PAB 55'	Radiation, Area, On Column Across From Sample Room	R64	
502J	E2	PAB 73'	Radiation, Area, Entrance Way To Volume Control Tank	N/A	X
502K	E2	PAB 73'	Radiation, Area, Hall Next To NPO Office	R65	
502L	E2	PAB 41'	Radiation, Area, South Wall Area Of Refueling Water Purification Pumps	N/A	X
502M	E2	PAB 41'	Radiation, Area, Hall On Column Next To Containment Spray Pumps	N/A	X
502N	E2	PAB 34'	Radiation, Area, Hall Near Entry To Safety Injection Pumps	R66	

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
502P	E2	PAB 41'	Radiation, Area, Pipe Tunnel In Area Of Chemistry Post Accident Sampling Station	R67	
502Q	E2	PAB 15'	Radiation, Area, On North Wall Adjacent To RHR Valve Gallery	R68	
502R	E2	RAB 15'	Radiation, Area, Hall On Wall At Entry To Filter Cell	N/A	X
502S	E2	PAB 54'	Radiation, Area, Within The Doorway On The Wall, Pipe Penetration	R69	
502T	E2	PAB 67'	Radiation, Area, Above Pipe Penn In Area Of Hydrogen Recombiner Panels	N/A	X
502U	E2	Fan Building 92'	Radiation, Area, In Area Of 4 Channel Iodine Monitors	R70	
502V	E2	Fan Building 72'	Radiation, Area, Outside Plenum In Area Of Differential Pressure Instruments	R70	
503A	E2	Containment	Radiation, Effluent, Noble Gas	R27	Via Plant Vent
504A	E2	Reactor Shield Building Annulus	Radiation, Effluent, Noble Gas	N/A	
505A	E2	Auxiliary Building	Radiation, Effluent, Noble Gas, Or Others Containing Primary System Gases	R27	Via Plant Vent
506A	E2	Cond Air Removal Sys Exhaust	Radiation, Effluent, Noble Gas	R15	NN
506B	E2	Cond Air Removal Sys Exhaust	Radiation, Effluent, Noble Gas – Flow Rate	R15	
507 A	E2	Common Plant Vent	Radiation, Effluent, Noble Gas	R27	SS
507B	E2	Common Plant Vent	Radiation, Effluent, Flow Rate	R27	SS
508A	E2	Steam Generator	Radiation, Effluent, Noble Gas From Safety Relief Valves Or Atm Dump Valves	R62	FF
509A	E2	Admin Bldg Exhaust Vent	Radiation, Effluent, Noble Gas From 4th Floor	R46	OO, CC

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	TYPE CAT	VARIABLE ONE	VARIABLE TWO	INST LOOP	NOTES
509B	E2	Admin Bldg Exhaust Vent	Radiation, Effluent, Flow Rate, 4th Floor	NONE	OO
509C	E2	Radioactive Machine Shop Exhaust Vent	Radiation, Effluent, Noble Gas	R59	
509D	E2	Radioactive Machine Shop Exhaust Vent	Radiation, Effluent, Flow Rate	FT-1776	
509E	E2	Steam Generator Blowdown	Radiation, Effluent	R19	
509F	E2	Steam Generator Blowdown	Radiation, Effluent, Flow Rate	F538	
510A	E3	Common Plant Vent	Radiation, Effluent, Particulates	N/A	EE, SS
510B	E3	Common Plant Vent	Radiation,, Effluent, Halogens	N/A	EE, SS
510C	E3	Common Plant Vent	Radiation, Effluent, Flow Rate	R27	
510D	E3	Admin Bldg Exhaust Vent	Radiation, Effluent, Particulates From The 4th Floor	N/A	DD, OO
510E	E3	Admin Bldg Exhaust Vent	Radiation, Effluent, Halogens From The 4th Floor	N/A	DD, OO
510F	E3	Admin Bldg Exhaust Vent	Radiation, Effluent, Flow Rate, 4th Floor	NONE	DD, OO
510G	E3	Radioactive Machine Shop Exhaust Vent	Radiation, Effluent, Particulates	N/A	CC
510H	E3	Radioactive machine shop exhaust vent	Radiation, Effluent, Halogens	NONE	CC
510J	E3	Radioactive machine shop exhaust vent	Radiation, Effluent, Flow Rate	FT-1776	
511A	E3	Environs	Radiation, Exposure Rate	N/A	RR
512A	E3	Environs	Radiation, airborne radiohalogens and particulates	N/A	portable instrum.
513A	E3	Environs	Radiation, photons	N/A	portable instrum.
513B	E3	Environs	Radiation, beta and low energy photons	N/A	portable instrum.

TABLE 7.5-1
Regulatory Guide 1.97 Instruments Required

REG GUIDE 1.97		STATUS OF COMPLIANCE			
INDEX	**TYPE CAT**	**VARIABLE ONE**	**VARIABLE TWO**	**INST LOOP**	**NOTES**
514A	E3	Environs	Radioactivity, multi channel gamma-ray spectrometer	N/A	
515A	E3	Meteorological	Met, wind direction	N/A	
516A	E3	Meteorological	Met, wind speed	N/A	
517A	E3	Meteorological	Met, atmospheric stability	N/A	
518A	E3	Sampling	Primary coolant and containment sump water analysis – gross activity	N/A	W,R
518B	E3	Sampling	Primary coolant and containment sump water analysis – gamma spectrum	N/A	W,R
518C	E3	Sampling	Primary coolant and containment sump water analysis – boron content	N/A	W,R

Table 7.5-1

Regulatory Guide 1.97 Instruments Required
NOTES

General Notes that apply to all items have an * as an identifier.

NOTE A: DELETED

NOTE B: The letdown flow is controlled by opening a remote operated valve, which allows flow through fixed orifice plates. The maximum CVCS letdown flow allowed administratively is limited to 120 gpm. It is the Authority's position that the indicated range (0-125 gpm) is adequate.

NOTE C: The existing level (18% to 82%) transmitter range is adequate. The modification necessary to obtain the additional level (0%-100%) required by 1.97 is not warranted based on manrem exposure and cost versus benefit.

NOTE D: The existing range indication for component cooling heat exchanger temperature is adequate for all modes of normal operation of off-normal modes of operation. The temperature of the component cooling system to date has not decreased below the existing range of 50°F. In addition, in the event of a major accident the temperature would be expected to increase as opposed to decrease, further assuring that the temperature would not decrease below the low range of the temperature system.

NOTE E: The existing range indication for component cooling heat exchanger flow is adequate for all modes of normal operation or off-normal modes of operation. The component cooling flow indication during normal operation may decrease below the existing range however; this condition does not cause any concern warranting a modification. The pump can be assured that it is functioning via low pressure and pump breaker status alarms. The components that are being cooled have local flow devices that are used to regulate the flow; therefore, minimum pump flow conditions can be met. In addition, in the event of a major accident, the flow would increase as opposed to decrease.

NOTE F: It is the Authority's position that sufficient indication to D.C. bus status is provided to the operators such that during post accident conditions, the operators will be aware of the operability of the D.C. buses.

NOTE G: Condensate storage tank level is currently monitored by two-(2) independent qualified transmitters. Diverse indication of CST level can be derived by auxiliary feedwater suction pressure indication. It is the Authority's position that the existing monitoring of CST level complies with the requirements of Regulatory Guide 1.97.

NOTE H: Boric acid flow to the RCS is monitored by the high-pressure injection (HPI) flow transmitters. Refer to index number 406 A-H which meets Reg. Guide 1.97 requirements.

NOTE I: Based on conversations with the NRC staff, the intent of this variable may be satisfied by the indication of several other variables. IP-3 has indication of RHR outlet temperature, containment spray flow and containment temperature which provides adequate indication of containment heat removal capability.

NOTE J: Adequate diverse measurement to PT-402 and PT-403 is obtained from pressure transmitters used to monitor pressurizer pressure (PT-455, 456, 457 and 474) for the range of 1700-2500 psig. Additionally, R.C.S. pressure, 0-3000 psig is indicated on a pressure gauge located in an area accessible to plant operators.

NOTE K: Each Steam Generator contains four (4) transmitters to indicate steam generator water level Three (3) transmitters per steam generator indicate narrow range level which is a span that begins at the top of the tube bundles to the moisture separator. The remaining level transmitter covers the span from the bottom tube sheet up to the moisture separator. Based on above, diversity exists from the top portion of the steam generator. Two (2) auxiliary feedwater flow indicators provide a diverse indication for the steam generator. In addition, since two of our four steam generators are required for heat removal, redundant wide range level for each generator is deemed not necessary.

NOTE L: Two (2) redundant level transmitters (LT-1253 & 1254) provide containment water level indication to the Central Control Room (CCR) operators. In addition, the containment sump and recirculation sump each contain (2) qualified level transmitters. The refueling water storage tank provides a diverse measurement for the containment water level.

NOTE M: Diversity is met via a third system which records saturation pressure margin and also use of steam tables.

NOTE N: Containment water level provides a diverse method to determine refueling water storage tank level.

NOTE O: Additional Containment pressure instrumentation exists (PT 948A, B & C and PT 949A, B & C) to provide a diverse means of establishing containment pressure.

NOTE P: Redundancy for the Hot Leg Reactor Coolant Temperature will be by the use of the core exit thermocouples (Diverse Variable). Redundancy for the Cold Leg Reactor Coolant Temperature is provided by the steamline pressure instrument PT 419 A, B & C; PT 429 A, B, & C; PT 439 A, B, & C and PT 449 A, B, & C (Diverse Variable).

NOTE Q: DELETED

NOTE R: DELETED

NOTE S*: On March 4, 1983, the NRC conducted a workshop in Chicago, Illinois in order to clarify the technical requirement of NUREG-0737, Supplement I. The handout distributed by the NRC at this workshop states that with respect to seismic qualification requirement for operating reactors, it will suffice to state that instrumentation systems comply with the seismic qualification program which was the basis for plant licensing. Accordingly, the seismic requirement is indicated

in Enclosure B as being satisfied if that instrumentation complies with the licensing basis for seismic qualification. [GENERAL NOTE]

NOTE T*: As noted in Regulatory Guide 1.97, Revision 3, Category 1 and 2 instrumentation should be qualified in accordance with Regulatory Guide 1.89, "Qualification of Class 1E Equipment for Nuclear Power Plants," and the methodology described in NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment." Enclosure B reflects this requirement for all Category 1 and 2 instrumentation. However, certain Category 1 and 2 instrumentation are located in mild post-accident environments and therefore are not within the scope of Regulatory Guide 1.89. For the sake of convenience, the Category 1 and 2 instrumentation located in a mild post-accident environment are noted as meeting Environmental Qualification (E.Q.) requirement. Hence, that instrumentation noted in Enclosure B as satisfying the E.Q. requirement either satisfy the requirements of 10 CFR 50.49 or are located in a mild post-accident environment.

NOTE U: Since the purpose of Pressurizer Heater Status is to ensure that they do not overload a diesel, adequate diesel generator loading information is available to the operators. The heaters are supplied by a safety related electrical bus and are stripped from that bus in the event of a Safety Injection Signal. They must be manually placed in service by the control room operator and procedures are in place that provide the guidance to ensure the diesels are not overloaded.

In addition, heater electrical breaker status lights are available. The pressurizer pressure and temperature response also provides verification that the heaters are operational.

NOTE V: DELETED

NOTE W: The Authority concurred with the NRC approach to post-accident sampling capability review. The deviations are beyond the scope of the Regulatory Guide 1.97 submittal and are best addressed via our submittal to NuReg-0737, Item II.B.3

NOTE X: Portable survey meters are the primary source of data on the radiation exposure rates inside buildings. These portable instruments are used to 1) verify the indication of the existing installed radiation monitors, and 2) determine exposure rates where there are no installed radiation monitors. It is Entergy's opinion that the portable survey meters meet the intent of the Guide.

NOTE Y: The automatic containment isolation valves at the facility meet all of the requirements of the Regulatory Guide on position indication. Non-automatic containment isolation valves are not provided with position indication. Valves that are considered essential and non-automatic are maintained in the open position and are closed after the initial phases of an accident. Approved emergency procedures are utilized to control the closing of these valves. Non-essential

containment isolation valves are maintained in the closed position and may be opened, if necessary, for plant operation and for only as long as necessary to perform the intended function, as required by Indian Point 3 Technical Specifications. These valves are additionally administratively controlled in the following manner:

1. Shift Manager approval for opening a non-automatic containment isolation valve is required.
2. An operator must be dedicated to the operation of these valves as long as they are in the open position.
3. Operator must have communications established with the Central Control Room, and
4. Operators first response to any emergency condition while the valve is open is to insure that the valve is returned to the closed position.

NOTE Z: Since the accumulators will discharge immediately when RCS pressure drops below accumulation pressure, these variables are unnecessary following an accident. Since power to the isolation valves is locked out at the circuit breaker, the operator would not be able to utilize these variables for manual actions, except for events in which the RCS pressure is decreasing very slowly. For such events, the present indicators are expected to function properly. Letter from NRC (N. F. Conicella) to R. Beedle, dated 9/28/92, entitled "REGULATORY GUIDE 1.97 – INSTRUMENTATION TO FOLLOW THE COURSE OF AN ACCIDENT FOR INDIAN POINT GENERATING UNIT NO. 3 (TAC No. M51099)", relaxed the requirement for Accumulator Pressure and Level Instrumentation and deleted the commitment for upgrading Accumulator Pressure and Level Instrumentation.

NOTE AA: The original radiation monitor used to monitor containment effluent radioactivity (R-12) is located in a non-harsh environmental area. Therefore, the environmental qualification requirements of the regulatory guide are satisfied. The combination of R-12 and an additional environmentally qualified effluent radiation monitor (R-27) sufficiently meets the range requirements of the Regulatory Guide.

NOTE BB: Radiation exposure rates inside buildings or areas in direct contact with primary containment where penetrations and hatches are located can be sufficiently monitored by portable radiation monitoring detectors.

NOTE CC: The existing sampler or radiation monitors for these areas do not meet the range requirements of the Regulatory Guide, however, it is Entergy's position that the indicated range is sufficient for the highest levels that are postulated for these areas.

NOTE DD: The existing area radiation monitors for these areas do not meet the range requirements of the Regulatory Guide, however, it is Entergy's position that these areas need not be monitored for the mitigation of an accident.

NOTE EE: To accommodate the range requirements of these radiation detectors, Entergy will use the Post Accident Sampling System.

NOTE FF: The plant computer will record the steam release duration and mass flow rate.

NOTE GG: Damper indication status is provided via red-green indicating lamps in the control room. The lamps are illuminated by a single limit switch, which is toggled when the damper is in the opened or closed position.

The Containment Fan Cooler units are provided with flow switches, which will cause an annunciation in the control room if low flow exists. In addition, a Weir system exists to quantify the cooling and condensing features of the ventilation unit.

Since failure of dampers are rare and it is improbable that the limit switch or some diverse variable would not detect the failure, it is Entergy's position that no modifications are warranted.

NOTE HH: The white lights used to satisfy Index 404A, B, C, and D are on when the valves are fully open and off when not fully open. These lights are always operable.

The valves are opened and the power and control circuits are de-energized when the RCS pressure is above 1000 psi. When these circuits are energized, each valve has red and green indicator lights which tell the operator whether the valve is full open, full closed or at some intermediate position.

NOTE II: The containment spray system consists of 4 spray headers. Two headers are used during the initial phase of the accident and the other two headers are used later in the accident. Manual operator action based on spray system flow rates is required in the later phase of the accident. As such, the spray flow indications described in Enclosure B are provided by the two headers used later in the accident only.

NOTE JJ: The existing level represents approximately 94% of the tank range. Since the tanks are horizontal cylindrical, the level actually monitors greater than 94% of its volume. These tanks are back up to 31 Waste Hold-Up tanks.

NOTE KK: The range that is required by the Guide, 0 to 165 psig, exceeds the tank design pressure and the tank safety valve setting, i.e., 150 psig. As additional status of tank pressure, an alarm is actuated when tank pressure reaches 110 psig. It is therefore concluded that the actual range of tank pressure is acceptable and meets the intent of the Regulatory Guide.

NOTE LL: DELETED – Monitor R-10 has been removed from the plant.

NOTE MM: The control room monitor's range is considered adequate. The operators would evacuate the control room prior to fields reaching the upper range prescribed in Reg. Guide 1.97.

NOTE NN: This possible atmospheric release point is designed to divert into the containment at relatively low levels. In addition, prior to reaching 1.97 levels, you would have to have fuel damage, steam generator tube failures and failure of the diversion to containment feature, which are highly improbable. Main steam radiation monitors are capable of detecting activity that would escape from condenser air ejectors. It is Entergy's position that the existing monitor is adequate to monitor the release point.

NOTE OO: The monitor is located and provides radiation level in an area that is not considered part of the plant proper. No radioactivity materials are expected to be brought into this area that would warrant any increase in the range of the existing monitors or the addition of flow monitoring devices.

NOTE PP*: As per Regulatory Guide 1.97 Rev. 3, seismic qualification is not required for Category II variables. [GENERAL NOTE]

NOTE QQ: DELETED

NOTE RR: No longer required as per Rev. 3 of Regulatory Guide 1.97.

NOTE SS: If the plant vent sampling capability, the wide-range vent monitor, or the main steam line radiation monitor is inoperable in MODES 1, 2, or 3, initiate a preplanned alternate sampling / monitoring capability as soon as practical, but no later than 72 hours after identification of the failure.

NOTE TT: The present list of qualified Core Exit Thermocouples is:
K-11, L-12, K-13, C-12, F-12, E-10, D-9, A-11, B-3, B-6, E-5, F-5, G-4, R-10, P-13, H-5, K-3, J-7, N-2, & L-1

7.6 IN-CORE INSTRUMENTATION

7.6.1 Design Basis

The in-core instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information obtained from the in-core instrumentation system, it is possible to confirm the reactor core design parameters and calculated hot channel factors. The system provides means for acquiring data and performs no operational plant control.

7.6.2 System Design

The in-core instrumentation system consists of thermocouples, positioned to measure fuel assembly coolant outlet temperature at preselected locations; and flux thimbles, which run the length of selected fuel assemblies to measure the neutron flux distribution within the reactor core.

The data obtained from the in-core temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. This method is more accurate than using calculational techniques alone. Once the fission power distribution has been established, the thermal power distribution and the thermal and hydraulic limitations determine the core capability and maximum power output.

The in-core instrumentation provides information which may be used to calculate the coolant enthalpy distribution, the fuel burnup distribution, and an estimate of the coolant flow distribution.

Both radial and azimuthal symmetry of power may be evaluated by comparing the detector information from quadrant to quadrant.

Thermocouples

Chromel-alumel thermocouples are passed through into guide tubes that penetrate the reactor vessel head through seal assemblies, and terminate at the exit flow end of the fuel assemblies. The thermocouples are provided with two primary seals, a conoseal and swage type seal from conduit to head. The thermocouples are enclosed in stainless steel sheaths within the above tubes to allow replacement if necessary. Thermocouple readings are obtainable via the plant computer and at a manually selected display unit in the control room. The support of the thermocouple guide tubes in the upper core support assembly is described in Chapter 3.

Moveable Miniature Neutron Flux Detectors

Mechanical Configuration

Six fission chamber detectors (employing U_3O_8, which is 93 percent enriched in U_{235}) can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. Maximum chamber dimensions are 0.188-inch in diameter and 2.10 inches in length. The stainless steel detector shell is welded to the leading end of the helical wrap drive cable and the stainless steel sheathed coaxial cable. Each detector is designed to have a minimum thermal neutron sensitivity of 1.5×10^{-17} amps/nv and a maximum gamma sensitivity of 3×10^{-14} amps/R/hr.

Maximum thermal neutron flux for these detectors is 5 x 10^{13} nv. Other miniature detectors, such as gamma ionization chambers and boron-lined neutron detectors, can also be used in the system. The basic system for the insertion of these detectors is shown in Figures 7.6-2 to 7.6-4. Retractable thimbles into which the miniature detectors are driven are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal zone.

The thimbles will be closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere. Mechanical seals provided on the retractable thimbles and on the conduits are shown on Figure 7.6-4.

During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of six drive assemblies, six 5-path rotary group selector assemblies and six 10-path rotary selector assemblies, as shown in Figures 7.6-2 and 7.6-3. The drive system pushes hollow helical-wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly generally consists of a gear motor which pushes a helical-wrap drive cable and detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length. Further information on mechanical design and support is described in Chapter 3.

Control and Readout Description

The control and readout system provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors at a selected speed while plotting a level of induced radioactivity versus detector position. The control system consists of two sections, one physically mounted with the drive units, and the other contained in the control room. Limit switches in each path provide feedback of path selection operation. Each gear box drives an encoder for position feedback. One 5-path group selector is provided for each drive unit to route the detector into one of the flux thimble groups. A 10-path rotary transfer assembly is a transfer device that is used to route a detector into any one of up to ten selectable paths. Manually operated isolation valves allow free passage of the detector and drive wire when open, and prevents steam leakage from the core in case of a thimble rupture, when closed. A common path is provided to permit cross calibration of the detectors.

The control room contains the necessary equipment for control, position indication, and flux recording. Panels are provided to indicate the core position of the detectors, and for plotting the flux level versus the detector position. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting and gain controls. A "flux-mapping" consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven or inserted to the top of the core and stopped automatically. A x-y plot (position vs. flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner other core locations are selected and plotted.

The system that will be used to monitor the distribution of power in the X-Y plane is described in WCAP-7669, "Topical Report – Nuclear Instrumentation System."

Operational limits due to a quadrant power tilt are given in the Technical Specifications.

The calibration of the Nuclear Instrumentation System by the movable incore detector system is made in accordance with the Technical Specifications. As noted in the Technical Specifications, the movable incore detector system shall be used to confirm power distribution.

After the excore system is calibrated initially, recalibration is performed periodically to compensate for changes in the core, due for example to fuel depletion, and for changes in the detectors.

If the recalibration is not performed, the mandated power reduction assures safe operation of the reactor as it will compensate for an error of 10% in the excore protection system. Experience at Beznau No. 1 and R. E. Ginna plants has shown that drift due to changes in the core or instrument channels is very slight. Thus the 10% reduction is considered to be very conservative.

The reactor trip functions (Section 7.2) provide core protection at the safety limits prescribed in the Technical Specifications. Those trip functions derived from the Nuclear Instrumentation System are described in WCAP-7669.

Each detector provides axial flux distribution data along the center of a fuel assembly. Various radial positions of detectors are then compared to obtain a flux map for a region of the core

7.6.3 System Evaluation

The thimbles are distributed throughout the core as shown in Figure 7.6-1. The positions have been chosen to provide symmetry checks and sufficient coverage, taking symmetry into account, to construct a full core three-dimensional power shape. With this number and location of thimbles the measurement accuracy for the peak to average rod in an x-y plane is 3.65% and for the peak to average pellet, including axial peaking, is 4.58%. These accuracies include the flux thimble to hot rod calculational uncertainty and instrumentation repeatability. They represent a 95% confidence level in a probability of fewer than 5% of cases lying above this error allowance. This confidence level and accuracy is consistent with the interpretation of DNB criteria.

The derivation and justification of these uncertainties is given in WCAP-7308-L, "Evaluation of Nuclear Hot Channel Factor Uncertainties."

7.6.4 System Operation

A. A minimum of 2 thimbles per quardrant and sufficient movable incore detectors shall be operable during recalibration of the excore axial offset detection system.

B. During the incore / excore calibration procedure, full core flux maps will be made only when at least 38 of the movable detector guide thimbles are operable.

7.7 OPERATING CONTROL STATIONS

7.7.1 Station Layout

The principal criteria of control station design and layout is that all controls, instrumentation displays and alarms required for the safe operation and shutdown of the plant are readily available to the operators in the Control Room.

During other than normal operating conditions, other operators will be available to assist the operators in the Control Room. Plant Drawings 9321-F-30523 and -33833 [Formerly Figure 7.7-1 and 7.7-2] show the Control Room layout and sections for the unit. The control board is divided into relative areas to show the location of control components and information display pertaining to various subsystems.

7.7.2 Information Display and Recording

Alarms and annunciators in the Control Room provide the warning to the operators of abnormal plant conditions which might lead to damage of components, fuel or other unsafe conditions. Other displays and recorders are provided for indication of routing plant operating conditions and for the maintenance of records.

Consideration is given to the fact that certain systems normally require more attention from the operator. The control system is therefore centrally located on the three section board.

On the left section of the control board, individual indicators present a direct, continuous readout of every control rod position. Fault detectors in the rod drive control system are used to alert the operator should an abnormal condition exist for any individual or group of control rods. Displayed in this same area are limit lights for each control rod group and all nuclear instrumentation information required to start up and operate the reactor. Control rods are manipulated from the left section.

Subsequent to periods of rod motion, when thermal equilibrium is being established in the rod position indicator coil stacks, temporary drifting of the indicators can be expected. During such time if indicated RCCA position differs from bank demand more than allowed by the Technical Specifications, the rod is treated as potentially misaligned under Technical Specification 3.1.4. Rod position is confirmed via a digital voltage meter applied to the rod position control racks. In addition, the operators will continue to monitor the affected rod position indicators on the main control board (and on the plant computer, if available and in agreement with the digital voltage meter reading) to check for increased deviation.

Variables associated with operation of the secondary side of the station are displayed and controlled from the control board. These variables include steam pressure and temperature, feedwater flow, electrical load, and other signals involved in the plant control system. The control board also contains provisions for indication and control of the reactor coolant system. Redundant indication is incorporated in the system design since pressure and temperature variables of the Reactor Coolant System are used to initiate safety features. Control and display equipment for station auxiliary systems is also located here.

The Engineered Safety Features Systems are controlled and monitored from a vertical panel to the left of the control board. Valve position indicating lights are provided as a means of verifying the proper operation of the control and isolation valves following initiation of the engineered safety features. Control switches located on this panel allow manual operation or test of individual units.

Also located on this section are the control switches, indicating lights, and meters for fans and pumps required for emergency conditions. Also mounted on this section are auxiliary electrical system controls required for manual switching between the various power sources described in Section 8.2.2.

Controls and indications for all ventilation systems, the containment isolation valves, and the Isolation Valves Seal Water System are located on a vertical panel. Radiation monitoring information is indicated immediately behind and to the left of the main control board.

Audible Reactor Building alarms are initiated from the radiation monitoring system and from the source range nuclear instrumentation. Audible alarms will be sounded in appropriate areas throughout the station if high radiation conditions are present.

7.7.3 Emergency Shutdown Control

The Control Room, its equipment and furnishings were designed so that the likelihood of fire or other conditions which could render the Control Room inaccessible even for a short time is extremely small. For details on the fire protection features, refer to Section 9.6.2.

A criterion of the station design and layout was that all controls, instrumentation displays and alarms required for the safe operation and shutdown of the plant are readily available to the operators in the Control Room.

It was design policy that the functional capacity of the Control Room should be maintained at all times inclusive of accident conditions, such as a Maximum Credible Accident or a fire; the following features were incorporated in the design to ensure that this criterion was met.

Structural and finish materials for the Control Room and the cable spreading room below were selected on the basis of fire resistant characteristics. Structural floors are concrete reinforced. Interior partitions are metal paneling joints. The Control Room ceiling covering is fire retardant egg crate diffusers. Door frames and doors are metallic. Wooden trim is not used.

The Control Room is equipped with portable fire extinguishers sized and located in accordance with National Fire Code and National Fire Protection Association specifications. Extinguishers carry the Underwriter's Laboratory label of approval and are electrical shock resistant.

Fire protection features of the cable spreading room and safe shutdown capability in the event of a fire in the cable spreading room are discussed in Section 9.6.2.

The Control Room ventilation consists of a system having a large percentage of recirculated air. The fresh air intake can be closed to control the intake of airborne activity if monitors indicate that such action is appropriate. Redundant control room toxic gas monitors are provided to alert the operators in the event that toxic gases exceed the short-term exposure limit (STEL).

Control cables used throughout the installation have been selected on the basis of flame testing described in Chapter 8 and have superior flame retardant capability. In addition, electrical circuits in the Control Room are limited to those associated with lighting, instrumentation and control. Lighting circuits operate on 120 volts, instrumentation and control circuits operate at either 120 volt AC, 125 volt DC or at millivolt level. All 120 and 125 volt circuits are protected

against both overload and short circuits by either fuses or circuit breakers. The power levels on the millivolt circuits are so low that it is inconceivable that short circuits in these could become a fire hazard.

No process fluids, combustible or otherwise, are carried into the Control Room.

Cables that penetrate the Control Room floor pass through sealing devices to minimize fume and flame transmission from possible fire sources external to the Control Room.

All internal wiring in switchboards and instrument racks has excellent resistance to propagation of flame. As a result of the design criterion discussed above the amount of combustible material in the Control Room is of such small quantity that a fire of the magnitude that would require evacuation of the Control Room is not credible.

As a further measure to assure safety, provisions have been made so that plant operators can shut down and maintain the plant in a safe condition by means of controls located outside the Control Room. During such a period of Control Room inaccessibility the reactor will be tripped and the plant maintained in a hot shutdown condition. If the period extends for a long time, the Reactor Coolant System can be borated to maintain shutdown as xenon decays.

Local controls are located so that the stations to be manned and the times when attention is needed are within the capability of the plant operating staff. The plant intercom system and other communication equipment provide for a flow of information among the personnel so that operation of the facility can be coordinated.

The functions for which local control provisions have been made are listed below along with the type of control and its location in the plant. Transfer to these local controls is annunciated in the Control Room.

Reactor Trip

If the Control Room should be evacuated suddenly without any action by the operators, the reactor can be tripped by any of the following actions:

1) Open rod control breakers in the control building

2) Actuate the manual turbine trip at the control standard in the turbine building, only if above P-8 setpoint 35%

3) Manually trip the rod drive Motor-Generator set in the Control Building

Following evacuation of the Control Room, the following systems and equipment are provided to maintain the plant in a safe shutdown condition from outside the Control Room:

a) Residual heat removal

b) Reactivity control, i.e., boron injection to compensate for fission product decay

c) Pressurizer pressure and level control

d) Electrical System as required to supply the above systems

e) Other equipment, as described

a) Residual Heat Removal

Following a normal plant shutdown, an automatic steam dump control system bypasses steam to the condenser and maintains the reactor coolant temperature at its no load value. This implies the continued operation of the steam dump system, condensate circuit, condenser cooling water, feedwater pumps and steam generator instrumentation. Failure to maintain water supply to the steam generators would result in steam generator dry out after some 34 minutes and loss of the secondary system for decay heat removal. Redundancy and full protection where necessary is built into the system to ensure the continued operation of the steam generators. If the automatic steam dump control system is not available, independently controlled relief valves downstream of each steam generator maintain the steam pressure. These relief valves are further backed up by code safety valves downstream of each steam generator. Numerous calculations, verified by start-up tests, have shown that with the steam generator safety valves operating alone the Reactor Coolant System maintains itself close to the nominal no load condition. The steam relief capability is adequately protected by redundancy and local protection.

For decay heat removal it is only necessary to maintain control on one steam generator.

For the continued use of the steam generators for decay heat removal, it is necessary to provide a source of water, a means of delivering that water and, finally, instrumentation for pressure and level indication.

The normal source of water supply is the secondary feedwater circuit. This implies satisfactory operation of the condenser, air ejector, condenser cooling circuit, etc. In addition to the normal feedwater circuit the plant may fall back on:

1) The condensate storage tanks
2) The city water storage tank
3) The city water supply

Feedwater may be supplied to the steam generators by the two electrical auxiliary feedwater pumps or by the steam driven auxiliary feedwater pump. These pumps and associated valves have local controls.

b) Reactivity Control

Following a normal plant shutdown to hot shutdown condition soluble poison is added to the primary system to maintain sub-critically. For boron addition the Chemical and Volume Control System is used. Routine boration requires the use of:

Changing pumps and volume control tank with associated piping. Boric Acid transfer pumps with tanks and associated piping. Letdown station, non-regenerative heat exchanger and associated equipment, Component Cooling and Service Water Systems. Compressed air for valve operation – manual could be adopted if necessary.

Control System. This requirement implies the charging pump duty referred to for boration plus a guaranteed borated water supply. The facility for boration is provided as described above; it is only necessary to supply water for makeup. Water may readily be obtained from normal sources, i.e., the volume control tank.

Startup of Other Equipment

Although not directly related to plant operation, certain ultimate heat sink safety analyses assume the air temperature inside containment is kept below 130°F. For this reason, the containment air recirculation fan coolers should continuously be in operation. If they have stopped, at least one should be restarted within five minutes, with the others started later as required. Similarly, the nuclear service water pumps will be checked and at least one of them restarted if none are already operating. The fan coolers and the service water pump remote controls are located in the switchgear room.

Electrical Systems

Offsite or onsite emergency power must be available to supply the above systems and equipment for the hot shutdown condition.

Indication and Controls Provided Outside the Control Room

The specific indication and controls provided outside the Control Room for the above capability are summarized as follows:

Indication

1) Level Indication for the Individual Steam Generators
   One set visible from the auxiliary feedwater pumps
   One set visible from the main feedwater control valves

2) Pressure Indication for the Individual Steam Generators
   One set visible from power operated atmospheric dump valve control stations.
   One set visible from the auxiliary feedwater pumps

3) Pressurizer Level and Pressure Indicators
   One set visible from the auxiliary feedwater pumps

It is worthy of note that with the reactor held at hot shutdown conditions, boration of the plant is not required immediately after shutdown. The xenon transient does not decay to the equilibrium level until at least 9 hours after shutdown and a further period would elapse before the reactivity shutdown margin provided by the full-length control rods had been canceled. This delay would provide useful time for emergency measures.

c) Pressurizer Pressure and Level Control

Following a reactor trip, the primary temperature will automatically reduce to the no-load temperature condition as dictated by the steam generator temperature, reducing the primary water volume and, if continued pressure control is to be maintained, primary water makeup is required.

One set visible from the charging pump local control point

4) RCS Temperature Indication
Loop #31 Thot and Tcold visible from the auxiliary feedwater pumps

5) RCS Flux Indication
Source range visible from the charging pump local control point

6) RCS Pressure
One set visible from the auxiliary feedwater pumps
One set visible from the charging pump local control point

All instruments at the auxiliary feedwater pumps are grouped on a local gauge board.

Alternate Power Supplies

Alternate Power Supplies have been provided for the following:

1) Component Cooling Water Pump 21
2) Charging Pump 31 or Charging Pump 32
3) Containment Safe shutdown instrument isolation cabinet

The alternate power supplies for items 1, 2, and 3 consist of manual transfer switches located near its respective load that can transfer the load from its normal power supply to the alternate power source – motor control center 312A located in the turbine building. Operation of the manual transfer switches to alternate power will give an annunciator alarm in the control room. Backup Service Water Pump 38 was removed from its normal supply (Bus 3A) and placed on MCC 312A as the normal supply.

Controls

Local stop/start pushbutton motor controls with a selector switch are provided at each of the motors for the equipment listed below. The selector switch will transfer control of the switchgear from the Control Room to local at the motor. Placing the local selector switch in the local operating position will give an annunciator alarm in the Control Room and will turn out the motor control position lights on the Control Room panel. The equipment consists of:

1) The Motor Driven Auxiliary Feedwater Pumps

2) The Charging Pumps

3) The Boric Acid Transfer Pumps

Remote stop/start pushbutton motor controls with a selector switch are provided for each of the motors for the equipment listed below. These controls are grouped at one point in the switchgear room convenient for operation. The selector switch will transfer control of the switchgear form the Control Room to the remote point. Placing the selector switch to local operation will give an annunciator alarm in the Control Room and will turn out the motor control position lights on the Control Room panel. The equipment consists of:

1) The Service Water Pumps 31 thru 36

2) The Containment Air Recirculation Fans
3) The Control Room Air Handling Unit Including Control for the Air Inlet Dampers

Key operated control switches located on MCC 312A provided local control for:

1) Component Cooling Water Pump 32
2) Charging Pump 31 or Charging Pump 32
3) Backup Service Water Pump 38

when utilizing the alternate power capabilities for items 1 and 2. Alternate motor control points are not required for the following:

1) The Component Cooling Water Pumps (Automatically restarted on a blackout once the diesel generators are operating)

2) The instrument Air Compressors and Cooling Pumps (These will start automatically on low pressures in the air and water services once the diesel automatically energizes the bus and the motor control centers are manually energized. The control point is local to the compressors.)

Isolation Switch Cabinets

Switching cabinets have been provided to permit local operation of Diesel Generator No. 31, its associated 480V load centers and to permit local indication of containment safe shutdown instrumentation (steam generator level, pressurizer level, RCS loop 31 temperature, RCS pressure and pressurizer pressure), independent of the effects of a cable spreading room fire. See Section 9.6.2.4.

Speed Control

Speed control is provided locally for:

1) The turbine Driven Auxiliary Feedwater Pump
2) The Charging Pump

Valve Control

Local valve control is provided at:

1) The Main Feed Regulators

2) The Auxiliary Feed Control Valves (These valves are located local to the auxiliary feedwater pumps)

3) The Atmospheric Dump (Auto control normally at hot shutdown)

4) All other valves requiring operation during hot standby

5) The Letdown orifice isolation valves locally to the charging pumps Local stop and start buttons with selector switch and position lamp are provided.

Pressurizer Heater Control

Stop and start buttons with selector switch and position lamp locally to the charging pumps for one 555 kW backup heater group are provided.

Lighting

Emergency lighting is provided in all operating areas as defined by the foregoing.

Communications

The communication network provides communications between the area of the auxiliary feedwater pumps and the charging pumps, boric acid transfer pumps, diesel generators, and the outside exchange without requiring the Control Room.

7.7.4 Cold Shutdown from Outside the Control Room

Hot shutdown is a stable plant condition, automatically reached following a plant shutdown. The hot shutdown condition can be maintained for an extended period of time. In the unlikely event that access to the Control Room is restricted, the plant can be safely kept at hot shutdown until the Control Room can be re-entered by the use of the monitoring indicators and the controls listed in Section 7.7.3. It is noted that these indicators and controls are provided outside as well as inside the Control Room.

By the use of appropriate equipment and procedures, the reactor can be brought to a cold shutdown condition from locations outside the Control Room if occupancy of the main Control Room should become untenable. The equipment systems that can be made available for a cold shutdown are as follows:

a) Auxiliary feedwater pumps

b) Boric acid transfer pumps

c) Charging pumps

d) Service water pumps

e) Containment fans

f) Component cooling pumps

g) Residual heat removal pumps

h) Controlled steam release equipment (e.g., steam dump valve) and feedwater supply

i) Equipment furnishing a boration capability

j) Safety injection pumps

k) Nuclear Instrumentation:
   1) Excore neutron flux detector channel associated with App R alternate capability

2) Alternate Power supply if instrumentation power is lost

l) Reactor coolant inventory control equipment (Charging and letdown)

m) Pressurizer, pressure control equipment (heater and spray) including opening control for pressurizer relief valves

n) Certain motor control center and switchgear sections which supply power to the above equipment

In addition, the safety injection signal trip circuit must be defeated and the accumulator isolation valves closed.

Detailed procedures to be followed in achieving cold shutdown from outside the Control Room are best determined by plant personnel at the time of a postulated incident. This is because an assessment of plant conditions can be made on a long term basis (a week or more) to establish procedures for making the necessary physical modifications to instrumentation and control equipment in order to attain a cold shutdown. During such time, the plant could be safely maintained at hot shutdown condition. The reactor plant design does not preclude attaining the cold shutdown condition from outside the Control Room.

7.8 MAXIMUM SAFETY SYSTEM SETTINGS AND MINIMUM CONDITIONS FOR OPERATION

Table 7.2-1 lists the reactor protection and engineered safety features actuation systems and Table 7.2-2 lists the associated interlocks. Maximum permissible settings for safe operation for these functions are given in the Technical Specifications.

7.9 SURVEILLANCE REQUIREMENTS

The requirements for periodic testing of instruments are listed in the Technical Specifications, Technical Requirements Manual, the FSAR, and the ODCM. The type of test action (i.e., channel calibration, channel operational test, etc.) to be taken and the minimum testing frequency (i.e., 31 days, 92 days, 24 months, etc.) for the indicated instruments are provided within the above-mentioned documents.

As indicated, the instrumentation channels which are covered include, for example, nuclear, reactor coolant temperature and flow, pressurizer pressure and level, and auxiliary process channels; or components necessary to assure that facility operation is maintained within the safe limits.

EXHIBIT FP 9- Supplement #1

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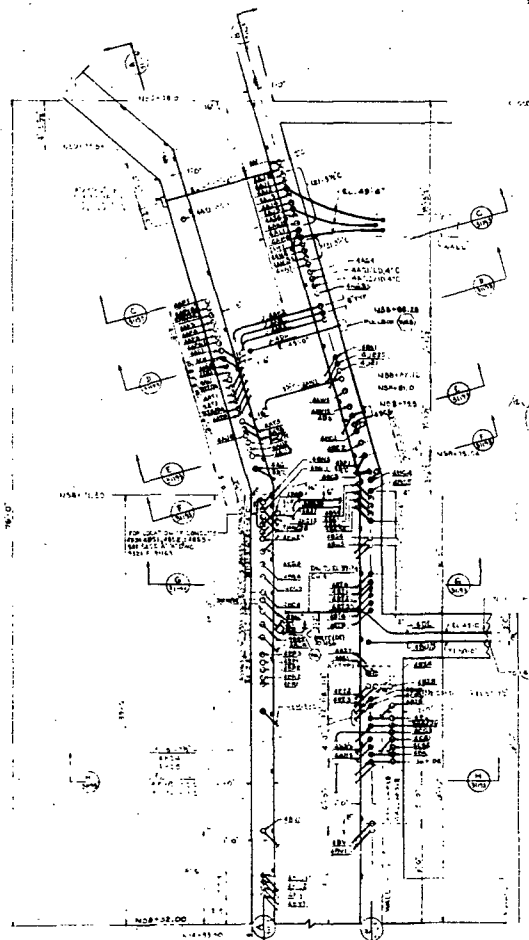
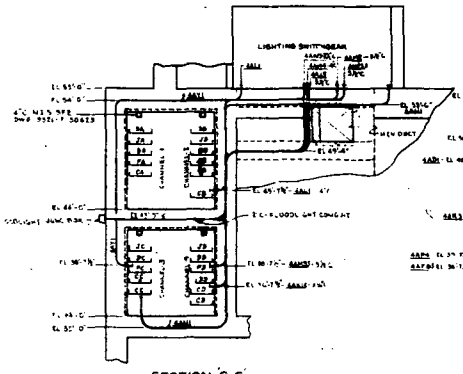
EXHIBIT 9 Supplemental #1

A202384



PARTIAL PLAN TUNNEL EL. 44'-0"



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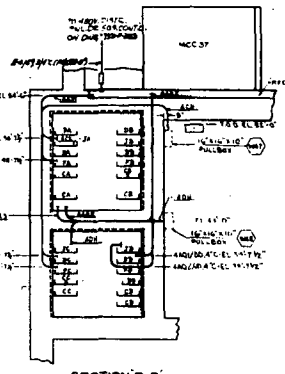

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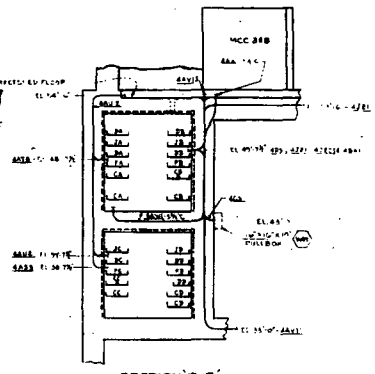

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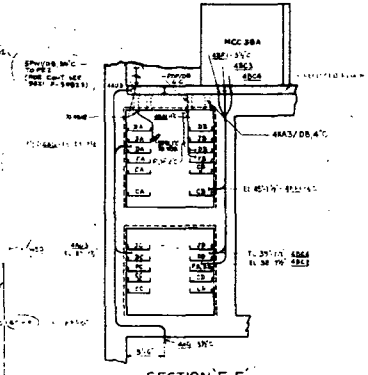

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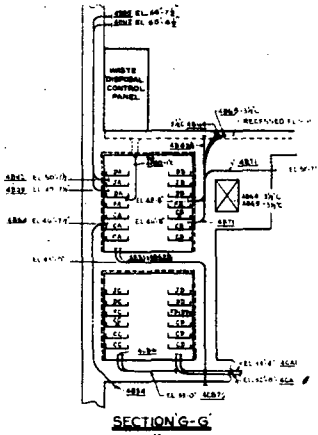

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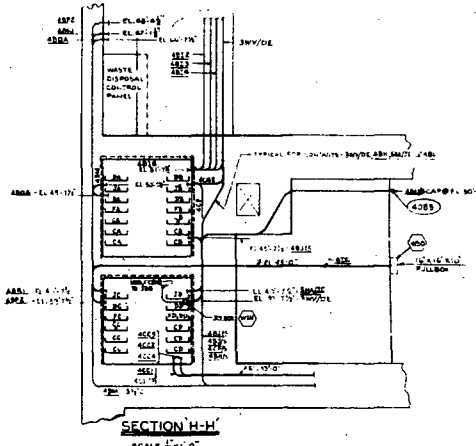

SECTION 'H-H'

SCALE 1/4"=1'-0" (9321-F-31193)

WESTINGHOUSE ELECTRIC CORPORATION

CONDUIT PLAN

P.A.B.- ELECTRICAL TUNNELS

ENCASED CONDUITS

FOR

CONSOLIDATED EDISON COMPANY

INDIAN POINT GENERATING STATION

UNIT NO. 3

UNITED ENGINEERS & CONSTRUCTORS INC.

9321-F-31193 A202384

Exhibit FP No. 10

REPORT ON THE NUCLEAR REGULATORY COMMISSION REACTOR SAFETY REVIEW PROCESS

By

Robert D. Pollard

Project Manager

Division of Project Management

U. S. Nuclear Regulatory Commission

February 6, 1976

INTRODUCTION

The purpose of this report is to prove two points. The points are that in reviewing the safety of nuclear reactors the Nuclear Regulatory Commission suppresses the existence of unresolved safety problems and fails to resolve those problems prior to allowing reactors to operate. The principal evidence of this practice is contained in "For Official Use Only" documents of the AEC and the NRC in *which* staff experts discuss reactor safety problems not brought to the attention of the public, particularly if to do so could delay the issuance of a license for a reactor.

This report is not a definitive statement of every unresolved and previously undisclosed safety problem. Such a report would require months of preparation by a task force and free, unfettered access to all of the internal documents of the NRC. In the brief time available all that could be done is to select some specific examples of what are recurring problems. The two large reactors owned by Consolidated Edison Company of New York and the Power Authority of the State of New York known as Indian Point 2 and Indian Point 3 have been selected for more thorough review. Their proximity to New York City (24 miles) and the substantial controversy that has surrounded them made them particularly appropriate for study. The public attention would presumably have produced the maximum disclosure of safety problems. The proximity to New York City

would presumably warrant the most careful safety review. As will be seen, even here where the highest safety should have been achieved, glaring defects remain.

This report is not a definitive safety evaluation of the Indian Point plants. Such an analysis has purportedly been completed by the Regulatory Staff. Rather specific examples are selected to illustrate the point being made. The examples begin in the late 1960'.s during the construction of Indian Point 2 and follow the history of Indian Point 2 and 3 through to today. This historical perspective highlights the long-standing existence of the review practices which suppress the **existence** and ignore the resolution of serious safety problems -- practices which have survived four Commission Chairpersons and seen two complete turnovers in the membership of the Commission. Clearly the problems are deep-rooted and extensive and the cure will require a far greater involvement of the Commissioners themselves than has previously occurred and a real commitment to the principle of "adequate protection for public health and safety" rather than "necessary protection for the vendor and utility investment".

This will hopefully be the first of many reports on the NRC safety review process. Further reports will depend upon the NRC's willingness to continue to allow access to internal documents. A decision now to shut the door on access to those

documents will of course not solve the problems, only hide them. What is most needed now is an open, public scrutiny of the NRC hand in hand with a Commissioner directed and conducted investigation. Unless this is done the same forces responsible for the sordid Indian Point story will apologize, camouflage and obfuscate the problems out of the public domain and it will once again be business as usual.

The four specific examples discussed in this Report relate to serious safety problems which currently exist at Indian Point 2 and 3. However, they are also to some extent generic problems which affect many plants. For instance the problem of reactor coolant pump overspeed remains unresolved for all PWRs. The problems described are by no means isolated examples. The Technical Activities Safety Report for December, 1975, a document claimed to be an "internal working paper" although it is published quarterly and lists the status of technical reviews seeking to resolve safety problems, lists nearly 183 specific serious unresolved safety problems as "currently receiving attention, [and] which have an important impact on the licensing review process" (Category A). Another 44 equally serious unresolved safety problems are described as "requiring NRR [Office of Nuclear Reactor Regulation] attention, but review has not been initiated because of manpower limitations or information is not available" (Category B). A third category of 8 serious unresolved safety

problems involve technical safety activities "planned for the future that would improve the quality of the review or facilitate the review process" (Category C).

These generic unresolved safety problems are so-fundamental to the basic evaluation of reactor safety that it is not possible to conclude on a technical basis that operation of any nuclear reactors is safe enough to provide reasonable assurance of adequate protection for the public health and safety. Even compliance with safety regulations can not be determined unless and until the unresolved safety problems have been resolved.

The seriousness of the unresolved problems is apparent to anyone who reads the December, 1975 Status Report. For illustration purposes a few examples are cited below:

Category A -- Currently receiving attention and have an important impact on the licensing review process.

Title: Definition of Experimental Program for Structural Response Evaluation to Turbine Missile Impacts

Problem Definition:

Information in the area of structural response to impacts of turbine missiles is seldom available if not totally lacking. The safety concerns derived from consideration of occurrence of a missile generated by failure of a turbine have been consistently expressed in almost all the ACRS letters to the Commission recommending issuance of CP or OL licenses during the last two years. Since there are significant differences between the parameters governing turbine generated missiles and that associated with tornado, the design procedures applicable to tornado generated missiles may not be applicable to protection barrier design against turbine missiles. An experimental program intended to develop design procedures and criteria for use in the protection barrier design against turbine missiles is urgently needed to resolve the outstanding concerns of both the ACRS and the NRC staff.

Current Status:

Only limited information related to turbine missiles is available. As a part of the work scope for item II.A.B.1, a preliminary definition for turbine missile experimental program was planned. However, NSWC could not undertake this task due to lack of available personnel. EPRI has indicated its interest to undertake limited tests designed to evaluate the impact of turbine missiles on reinforced concrete barriers.

Plans for Resolution:

A fairly extensive experimental program intended for obtaining the structural response data to turbine missile impacts will be proposed in FY 77. The program scope will depend on future work to be undertaken by EPRI. [EPRI is industry supported)

Schedule for Completion:

To be established later.

Category B -- Require attention but review not yet initiated due to lack of manpower or lack of information.

Title: Calculation of Dose Rates from Certain Radioactive Sources at Nuclear Facilities

Problem Definition:

In order to evaluate radiation exposure to nuclear power plant employees, visitors, onsite construction workers, etc., it is necessary to determine the dose rate at specific onsite locations due to specific radioactive sources in the plant. These include storage tanks for low level radioactive liquids, the turbine building sources in a BWR, etc. Simple calculational methods are needed to give reasonably accurate, fast results for these cases for various evaluations which the staff is required to carry out.

Current Status:

Some empirical formula exist for such cases. These are limited in application, in both accuracy and useful range. New data have been taken at two BWR power plants and are being evaluated.

Plans for Resolution:

Discussions have been held with various contractors in the area of radiation transport calculations. Measurements have been made around certain BWR nuclear power plants. It is our plan to use the information gathered in both these activities to develop either better empirical formula or to develop calculational methods which will treat the cases of concern.

Schedule for Completion:

One Year

Category C -- Reviews planned for the future that would improve the quality of or facilitate the safety reviews.

Title: Economics of Occupational Radiation Exposure Reduction at Nuclear Facilities

Problem Definition:

Very little data exists on the costs related to the many methods available for occupational radiation exposure reduction at nuclear power plants. Information is also lacking on the benefit in man-rem reduction that is related to these methods. These data are needed in order to make a quantitative determination of the occupational radiation exposure that is ALAP for a particular nuclear facility.

Current Status:

Talks have been held with various segments of industry. Data has been collected on exposure related to certain activities and steps have been taken to get additional pertinent input.

Plans for Resolution:

As data and information become available, Radiation Protection Section staff members will develop a generic description of the proper means to evaluate the economics of radiation exposure reduction. Some guidance in this regard is being developed for the revised Regulatory Guide 8.8, now in progress.

Schedule for Completion:

Two years

What follows is a description of four specific serious safety problems at Indian Point 2 and 3 which have not been resolved but the existence of which are well known to those at NRC charged with the responsibility of deciding whether to allow a reactor to begin operating or to continue to operate. These "responsible" officials have no adequate technical justification for allowing reactor operation in the face of these problems. The justification is the implementation of the NRC policy that priority be given to the goal that reactor operations not be interrupted or delayed. On rare occasions this goal has not been achieved such as when an Intervenor "discovers" the existence of one of these unresolved safety problems (i.e. the fuel densification problem resulting in derating or operating modifications to twenty BWRs). Hopefully the disclosures contained in this Report will result in similar actions.

ILLUSTRATIVE SAFETY PROBLEMS

T. CONTAINMENT ISOLATION

The General Design Criteria set forth in Appendix A to 10 CFR Part 50 establish the "minimum requirements for the principal design' criteria for water-cooled nuclear power plants". (10 CFR Part 50.34) General Design Criteria 54, 55, 56 and 57 establish minimum requirements concerning isolation of piping systems that penetrate the reactor containment. Criterion 55 and Criterion 56 specify four containment isolation valve arrangements. Each isolation valve arrangement involves a combination of locked closed isolation valves and/or automatic isolation valves to prevent the release of radioactive material. These criteria specify that one of the four valve arrangements "shall be provided -- unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis".

In contrast to these specific requirements, the staff is aware that many of the lines at the Indian Point 3 plant do not have isolation valve arrangements which correspond to any of the arrangements specified by Criterion 55 and Criterion 56. Furthermore, neither the staff nor the licensee has identified a "specific class of lines" that need not utilize the specified arrangements. Nor has either the staff or licensee identified "some other defined basis" on which the Indian Point 3 isolation valve arrangement can be demonstrated to be acceptable.

Rather than adhere to the requirements of the General Design Criteria, the licensee has proposed technical specifications which would permit plant operation with containment isolation valves (which have no provision for automatic closure) in their open positions. The licensee states that reliance on the reactor operator to manually initiate closure of such valves is adequate. The staff apparently gives tacit approval to this evasion of NRC regulations by stating the "We have reviewed the isolation valve arrangements for conformance to General Design Criteria **54, 55, 56** and 57, and conclude that the design meets the intent of these criteria". (Safety Evaluation of the Indian Point Nuclear Generating Unit No. 3, dated September 21, 1973).

This is one of the safety problems I became aware of as project manager for Indian Point 3. The pressure to issue a license on a schedule compatible with the applicant's desires notwithstanding, I questioned those staff personnel with specific expertise in the reactor containment area about their bases for accepting the Indian Point 3 design. Their responses indicated that: a) it was known that the design did not meet the General Design Criteria, b) the design was not different than other licensed nuclear power plants, and c) it was too late to require design changes to the plant. These experts stated that they saw

no reason to change their **previous** conclusions as stated in the Indian Point 3 Safety Evaluation Report and referenced above. The bases for these conclusions remain obscure if not non-existent. The staff's' Safety Evaluation Report mentions the "double barrier protection -- provided so that no single valve or piping failure can result in loss of containment integrity". Also described briefly are the two groups of containment isolation valves which are closed automatically by the safety injection signal and the actuation of containment spray. No mention is made of the non-automatic containment isolation valves, the criteria used to judge the acceptability of reliance on manual operator action, or the specific "closed system" which is purported to constitute one of the barriers to escape of radioactive materials.

I believe that the-provisions for containment isolation following an accident at Indian Point 3 should be evaluated or re-evaluated. If the present design and proposed technical specifications are found acceptable, the NRC should state the specific technical bases for its conclusion that the design meets the NRC regulations. Indian Point 2 should also be evaluated in this regard. It **is likely** that the situation there is the same as or more hazardous than the situation at Indian Point 3.

The staff should have discussed the non-automatic containment isolation valves, the nature of the "closed systems upon which the "acceptability" was partially based, and the criteria used

to judge the adequacy of manual operator action.
The Safety Evaluation Report, in discussing only those aspects of containment isolation which were not a problem and then stating the conclusion that the design meets the "intent" of the General Design Criteria, presented a more favorable picture of containment isolation than the actual design warrants. By presenting only the favorable aspects, the remainder of the licensing process, i.e., scrutiny by public, independent decisions by the licensing boards, was subverted and therefore less likely to be able to reach a sound decision based on all the facts.

II. SUBMERGED VALVES

During my assignment as project manager for the Indian Point 3 plant, the problem concerning submerged valves arose. Basically, this problem is that following an accident, much of the water from the reactor coolant system and from operation of the emergency core cooling systems collects in the containment. Recently, it has been discovered that many valves located inside the containment, including some valves intended to be used to mitigate the consequences of accidents, could become submerged and, thereby, rendered inoperable. Why the vendor, applicant or staff did not discover this problem over the past years is a question worth explaining for the future, with the aim of preventing similar fundamental oversights. For now, it is better to concentrate on determining an acceptable solution to the problem.

Con Ed has proposed a scheme to solve the problem. Basically, their proposal is to elevate only a few of the valve motors (but not the valves) above the calculated water level which is expected following an accident. For most of the valves whose motors will be sacrified, Con Ed has expressed their conclusion that this **will have** no adverse effect on accident consequences. Since not **all** the valve motors (which were previously to be relied upon to cope with the accident) will be elevated, it is necessary to modify equipment and to develop new operating procedures for the manual operator actions that are required soon after the accident. Whether the new procedures and resulting core cooling system performance using these new procedures have been evaluated as thoroughly as the original design by either the staff or the applicant is questionable. Whether the plant operators have been adequately "debriefed" on the old procedures and retrained in the **use** of the new procedures is also questionable.

The deficiencies in the evaluation of the revised design and operating procedures are illustrated by the following questions which have not been adequately analyzed:

a) Do the platforms used to support the elevated motors have adequate capability to withstand an earthquake? (Of course, until a decision concerning the magnitude of the earthquake that must be withstood is reached, the question of the seismic adequacy of the entire plant remains unanswerable.)

b) **Is there** any circumstance under which the sub-**merged valves** might be needed to cope with an accident, especially if the accident sequence does not follow the predicted sequence?

c) What "new" " equipment will need to be relied on, e.g., core cooling system flow instrumentation? Has this equipment been designed, procured and installed in accordance with the regulations and standards applicable to safety equipment?

d) What are the disadvantages (and what are their significance) of using operator's trained on Unit 2 to operate Unit 3 which has had substantive design changes compared to Unit 2?

e) What other equipment besides valves will become submerged following an accident? Has the effect on safety of submerging this equipment been evaluated?

More urgent from a public safety viewpoint than the review of Indian Point 3 is the question of the status of Indian Point 2 and other operating plants. The most recent correspondence on this matter (Reference 35) of which I am aware seems to indicate that nothing will be done to alter plant design or operating procedures prior to "the first refueling outage (which) is currently scheduled to commence April 1, 1976". 1 consider

this to be a totally irresponsible course of action. The NRC should not allow continued operation of a plant when there is good cause to believe that an unresolved safety question exists and that the plant is not in compliance with the regulations. In fact, the regulations would appear to require a completely different course of action (see 10 CFR 50.100). Legal interpretation of the regulations notwithstanding, the proper course for a purely regulatory agency to follow is to permit operation only when there are sound technical bases to demonstrate safety of operation rather than to permit operation until the licensee or public can provide the sound technical bases for requiring immediate shutdown of the plant.

III. PUMP FLYWHEEL MISSILES GENERATED BYREACTOR COOLANT PUMPOVERSPEED

References 37 through 50 are some of the documents which discuss this unresolved safety problem

As a result of a reactor coolant system pipe rupture and the blowdown of reactor coolant through the reactor coolant pump, "the pump impeller may act as a hydraulic turbine causing the pump, motor, and the flywheel to overspeed and become potential sources of missiles". (Reference 38) This is a significant problem because of the tremendous inertial energy of the missiles, especially flywheel parts, and the difficulty of predicting the course of these missiles. Whether containment integrity can be

maintained and whether the performance of emergency core cooling systems can be assured if pump missiles are generated following a LOCA are significant unresolved questions.

Numerous statements by experts on the staff and outside the agency indicated the severity of the problem. It is not practical to limit overspeed by mechanical braking systems because of the significant amounts of energy they would have to absorb. Furthermore, inadvertent operation of a braking system could result in a locked rotor accident. Provision of barriers to retain any missiles also appears impractical and could also significantly increase the cost of construction.

During the review, expert after expert expressed the conclusion that empirical data was needed to determine the magnitude of the threat to the health and safety of the public. For example:

> "Unfortunately, due to the sparsity of empirical information, the above statement (that the pump may not overspeed) has to be considered as speculative at the present time." (Reference 41)

> "Two-phase pump performance is an area which requires further investigation. The evaluation of the accuracy of any particular model depends on the performance of adequate pump tests which simulate the conditions expected during a LOCA." (Reference 37)

> "A large uncertainty is associated with the prediction of the hydraulic torque generated by a time-varying, two-phase fluid passing through the impeller at sonic or near sonic conditions... Although the theory of pump and turbine performance is understood, designers resort to experimental programs or at least to confirmatory tests even for normal operation to establish performance characteristics". (Reference 44)

> "The summary of my presentation incorrectly contains the assertion that the current treatment of two-phase flow behavior results in conservative overspeed predictions. My position is that we do not know whether the results are conservative or not and to the best of my recollection that is the view I expressed in the presentation". (Reference 49 enclosure)

Attempts to justify continued licensing and operation of plants while this problem remains unresolved met with similar **expressions** of disagreement. Aside from the generic excuse that the occurrence has a low probability the only other argument available is the **use** of electrical braking to prevent overspeed. Reference 45 details the arguments against electrical braking as a method of protecting' the health and safety of the public. Reference 47 also expresses succinctly a disagreement with unsupported reliance on expected experimental results, low probability of occurrence, or electrical braking.

In summary, the potential for missiles from pump overspeed remains an unresolved safety problem for Indian Point 2 and 3, as wells other plants. Based on the files concerning review of the Westinghouse topical report, WCAP-8163, the status of resolution is that, as of August 13, 1975, the staff is waiting for information. I believe this matter should be reconsidered in connection with continued operation of Indian Point 2 and commencement of operation of Indian Point 3 as well as a similar reconsideration in connection with all PWRs.

*/ The low `probability argument has not been accompanied by a discussion of the consequences of such an accident.

IV. SEPARATION OF ELECTRICAL EQUIPMENT

Much emphasis is placed on the single failure criterion in attempting to assure the public that nuclear plants are safe. Much less emphasis is given to the underlying assumptions which must be satisfied in order that the single failure criterion be a valid criterion. One of these basic assumptions is that failures will occur only in a random manner. Stated another way, the assumption is that failure (or operation) of one system or component will not affect the performance of its redundant counterpart.

One of the basic methods used to try to satisfy this assumption is to physically separate redundant equipment. The separation must be sufficient both to assure that failure of one safety system does not cause failure of the other and to assure that failures in non-safety systems do not cause failure of either safety system. A more detailed explanation of this philosophy can be found in IEEE Std 379 and the NRC standard review plan Chapter 7.

Based on my knowledge of the Indian Point 2 and 3 designs and the current separation criteria, I conclude that the physical separation provisions at Indian Point 2 and 3 are not adequate for the health and safety of the public. There is no adequate basis for concluding that a common mode failure will not result in a very serious accident other than sheer good luck. In fact,

based on the documents in the NRC files, this conclusion appears to be almost identical to the conclusions other knowledgeable staff members reached as early as 1969.

An ACRS Subcommittee meeting was held in April, 1970 and the staff made a rather detailed presentation of the poorer design aspects related to the *Indian* Point 2 protection and electrical systems. This included discussion of the single cable tunnel, the engineered safety feature manual actuation panel in the control room without separation in the panel, the common diesel location in a sheet metal structure, cable separation, and cable penetrations at the containment. "The Subcommittee was 'appalled' at the situation. They asked if we did not have an Oyster Creek situation in hand and whether we should not have the applicant make an independent review of his work as we required of Jersey Central." (Reference 18)

By the time the Electrical Systems Branch provided its input (Reference 22) for use in preparing a report to ACRS the electrical items which did not meet present day criteria earlier in the review, had either been "accepted", "resolved", or "approved with some reluctance", or they remained "unresolved".

The two reports to the ACRS prepared by the staff and classified as "Official Use Only" (References 26 and 28) should be reviewed by NRC to determine whether the previous bases for reluctantly accepting design deficiencies are adequate for protecting

the health and safety of the public. Based on those reports, it appears that many items were accepted solely because so many other areas of the plant were deficient that it wouldn't do much good to require upgrading only a few. In other cases, it appears that a judgment-was made that the cost in time and money needed to provide substantial additional protection for the public health and safety was too great. The bases for this staff conclusion should be made public.

In the case of the separation between Unit 2 diesels, the apparent resolution is inconsistent in itself. The applicant claimed that there was no history of diesel explosions that damaged the diesel's environs. Nevertheless, a concrete wall was installed to protect the common control panel but no similar protection was installed between the diesels.

In summary, I consider the physical separation, or more accurately the lack of adequate physical separation, to be one of the significant safety hazards at Indian Point 2 and 3 which should be reconsidered. The single electric cable tunnel, the cable spreading room, the containment electrical penetration area, the main control board, the-safety injection pump and containment spray pump areas, and the auxiliary feedwater pump areas are among the vital areas that should be re-evaluated.

*/ The fact that Unit 3 has two cable tunnels is not significant Because the system logic requires that two out of three systems be operable following an accident. In addition, the problem of associated circuits was apparently not considered at all.

CONCLUSION

Attached as Appendix I to this Report is a bibliography of documents providing even greater detailed evidence of the existence of unresolved safety problems and of the deliberate refusal of the Regulatory Staff to take these problems into account in their safety reviews on individual reactors or even to publicly reveal the existence of the problems. Most of these documents have not been placed in the Public Document Room or otherwise made available to the general public. The release of these and similar so-called internal memoranda is essential if public participation in licensing decisions and independent licensing board reviews is to have any meaning. At present these processes involve a very limited examination of licensing decisions, inhibited by the Staff refusal to honestly disclose the serious unresolved safety problems that are known to it and that are relevant to licensing decisions.

This Report is based on materials contained in the NRC internal files and available to any NRC official sufficiently concerned to want to look into the files. The Report demonstrates that the NRC is fully aware of serious unresolved safety problems but deliberately refuses to allow these problems to interfere with licensing. If any NRC official wants to be responsive to the concerns of this report he or she should focus on ways of removing the censorship from disclosure and handling of these problems in

licensing reviews, not to ask those responsible for suppressing **the existence** of the problems to give rationalizations for their prior failures to take action on these problems.

This is a great cross-roads for the NRC. It can continue on the current path of. encouraging rapid and uninterrupted reactor licensing while seeking to defend itself from valid criticism or it can follow the new path charted for it by Congress in declaring that the sole agency function is to regulate nuclear power to protect the public health and safety regardless of the impact on the nuclear industry or electric utilities. The purpose of this Report is to inform the public of the present state of the NRC safety review process and to thereby put pressure on the NRC to fulfill its statutory responsibilities.

APPENDIX I

DOCUMENTS RELATED TO OR BEARING ON
THE REPORT ON THE NUCLEAR REGULATORY
COMMISSION REACTOR SAFETY REVIEW PROCESS
BY ROBERT D. POLLARD

DATED FEBRUARY 6, 1976

A. INDIAN POINT 2 DOCUMENTS

1. Report to the Advisory Committee on Reactor Safeguards in the matter of Indian Point Unit No. 2, February 23, 1968 - OFFICIAL USE ONLY.

2. Memorandum to R. S. Boyd from V. A. Moore, March 11, 1969, reporting the results of "a cursory examination of the Indian Point #2 FSAR in order to identify major areas of concern".

3. Memorandum to Roger S. Boyd from V. A. Moore, March 17, 1969, reporting additional areas of concern as a result of meeting with the applicant on March 12, 1969.

4. Memorandum to R. S. Boyd from Karl Kniel, April 17, 1969, summarizing the discussions with the applicant on March 12, 1969.

5. Memo Route Slip to R. C. DeYoung from V. A. Moore, June 10, 1969, discussing problems with the proposed Indian Point No. 2 questions dated June 6, 1969.

6. Memo Route Slip to Ray Fraley from Roger S. Boyd, August 19, 1969, transmitting "some draft copies of an informal report on our Indian Point 2 review -- for use by the (ACRS) Subcommittee at the August 23 meeting".

7. Report to the ACRS, Indian Point Nuclear Generating Unit No. 2, August 19, 1969 - OFFICIAL USE ONLY.

8. Memorandum to Peter A. Morris from Voss A. Moore, Jr., September 8, 1969, discussing and providing additional information on the areas' of concern identified by 3. above.

9. "Note to Pete (Morris)" from R. S. Boyd, September 19, 1969 responding to "poison pen memo RT-671A". (Note: RT-671A is item 8. above)

10. Memorandum to R. T. Carlson from Olan D. Pare and Vincent D. Thomas, January 5, 1970, transmitting results of the Indian Point No. 2 Plant inspection of December 15-19,1969.

11. Memorandum to Saul Levine from O. D. Parr and R. D. Pollard, January 12 1970, providing minutes of meetings held on December' and 30, 1969.

12. Memorandum to Peter A. Morris from Voss A. Moore, Jr., January 16, 1970, discussing "electric items which do not meet present day criteria".

13. Memorandum to Saul Levine from O. D. Parr and R. D. Pollard, January 29, 1970, providing the minutes of the meeting held on January 16, 1970, and identifying unresolved items.

14 Memo randum to Peter A. Morris from Edson G. Case, April 3, 1 70, regarding "unresolved electrical and instrumentation items". (Note: The Electrical, Instrumentation, & Control Systems Branch's file copy also has identified whether the eight areas were "accepted", "resolved" or remained "unresolved". No explanation is recorded concerning the difference between "accepted" and "resolved".)

15. Memo Route Slip to Edson G. Case from Voss Moore, April 7, 1970, providing a tabulation of those areas "which we believe have been resolved but not documented".

16. Letter to R. C. DeYoung from M. W. Libarkin, April 2, 1970, regarding the tentative agenda for the ACRS Subcommittee meeting on April 25, 1970.

17. Memo Route Slip to Edson G. Case from Voss A. Moore, April 14, 1970, regarding assignments to prepare to discuss each of the items on the ACRS Subcommittee agenda.

18. Memorandum to P. A. Morris from R. C. DeYoung, May 5, 1970, transmitting a "summary report of the ACRS Subcommittee meeting on Indian Point 2 held at O'Hare Airport on April 25,. 1970".

19. Letter to R. C. DeYoung from M. W. Libarkin, May 15, 1970, regarding the tentative agenda for the ACRS Subcommittee meeting on May 28, 1970.

20. Memorandum to R. C. DeYoung from Karl Kniel, May 15, 1970, transmitting a "summary report of a meeting on Indian Point 2 held at 1717 H Street on May 5, 1970."

21. Memorandum to P. A. Morris from Edson G. Case, May 18, 1970, transmitting a report on the engineered safety feature manual actuation panels to be used in case "the ACRS agrees to consider the problem".

22. Memorandum to P. A. Morris from Edson G. Case, May 19, 1970, transmitting a "report -- prepared by the DRS Electrical Systems Branch for use in the DRL ACRS report concerning the Indian Point No. 2 plant".

23. Memorandum to R. C. DeYoung from Karl Kniel, May 25, 1970, transmitting a "summary report of an ACRS Subcommittee Meeting, held at the site on May 11, 1970".

24. Letter to Dr. Joseph M. Hendrie from Peter A. Morris, June 5, 1970, transmitting a "Special Report to the ACRS, Indian Point Nuclear Generating Unit No. 2, Operating License Review" relating to two unresolved items concerning reactor protection and engineered safety feature instrumentation and controls - OFFICIAL USE ONLY.

25. Letter to Dr. Peter A. Morris from R. F. Fraley, June 17, 1970, regarding "resolution of items discussed during the 122nd ACRS meeting".

26. Report to the ACRS, Indian Point Nuclear Generating Unit No. 2, Operating License Review, July 2, 1970 - OFFICIAL USE ONLY.

27. Letter to Consolidated Edison from Peter A. Morris, July 24, 1970, transmitting additional questions regarding Indian Point 2.

28. Report to the ACRS, Indian Point Nuclear Generating Unit No. 2, Operating License Review, Report No. 2, September 4, 1970 - OFFICIAL USE ONLY.

29. Memorandum to P. A. Morris from Edson G. Case, September 10, 1970, transmitting additional information to supplement the report transmitted on May 19, 1970 (Item 22. above).

30. Safety Evaluation by the Division of Reactor Licensing in the matter of Indian Point Nuclear Generating Unit No. 2, November 16, 1970.

31. Memorandum to J. P. O'Reilly from N. C. Moseley, March 18, 1971, transmitting CO Report No. 247/71-4 by G. L. Madsen dtd 3/10/71.

32. **Supplements Nos. 1, 2 and 3 to the** Safety Evaluation by the Division of Reactor Licensing in the matter of Indian Point **Nuclear** Generating Unit No. 2.

33. memorandum to R. C. DeYoung from R. H. Engelken, November 16, 1971, regarding a preliminary report of the Indian Point **fire**.

34. Memorandum to J. G. Keppler from Eldon J. Brunner, February 4, 1972, transmitting Co Inquiry Report No. 50-247/7203.

35. Letter to Robert W. Reid from William J. Cahill, Jr., September 15, 1975, regarding future action for resolution of the submerged valve problem and analysis of the Indian Point 2 emergency core cooling system performance.

36. Memorandum to Robert W. Reid from Zoltan R. Rosztoczy, December 8, 1975, regarding "evaluation of Con Ed's proposed change of reactor coolant pump underfrequency trip setpoint".

B. DOCUMENTS RELATED TO MISSILES GENERATED BY REACTOR COOLANT PUMP OVERSPEED DURING A LOSS OF COOLANT ACCIDENT.

37. **Report**; R. F. Farman and N. R. Anderson, "A Pump Model for Loss-of-Coolant Accident Analysis, date unknown. (This work was performed by Aerojet Nuclear Company for AEC under Contact AT(10-1) -1375.)

38. Memorandum to R. C. DeYoung from R. R. Maccary, January 26, 1973, regarding evaluation of pump flywheel overspeed.

39. Note to R. C. DeYoung from R. W. Kiecker, March 14, 1973, transmitting copies of notes of the meeting held with reactor vendors regarding reactor coolant pump overspeed during a LOCA.

40. Memorandum to D. F. Ross from Paul E. Norian, June 19, 1973, regarding calculations of PWR pump overspeed during a LOCA.

41. Note to' R. C. DeYoung from R. W. Klecker, July 5, 1973, providing a brief discussion of reactor coolant pump overspeed during a LOCA "which may be useful as background information for further AEC deliberations regarding this matter".

42. Memorandum to R. C. DeYoung from R. W. Klecker, July 10, 1973, transmitting minutes of a joint meeting on pump overspeed analytical models.

43. Letter to Mr. Howard Arnold of Westinghouse from R. C. DeYoung, July 19, 1973, requesting a report on various aspects of the pump overspeed problem. (Note: Distribution did not. include the Public Document Room)

44. Note to S. H. Hanauer, et al. from R. C. DeYoung, July 27, 1973, transmitting a draft of the proposed presentation to ACRS on pump overspeed during a LOCA.

45. Memorandum to Victor Stello, Jr. from T. A. Ippolito, August 3, 1973, transmitting an evaluation of electrical braking as a means of limiting pump overspeed during a LOCA.

46. Letter to Harold C. Mangelsdorf from R. C. DeYoung, August 6, 1973, transmitting the staff's report on reactor coolant pump overspeed during a LOCA.

47. Memorandum to John F. O'Leary from S. H. Hanauer, August 9, 1973, titled "Pump Overspeed Patches" transmitting comments on the report on reactor coolant pump overspeed during a LOCA.

48. Memo-Route Slip to R. C. DeYoung, et al. from Dr. Hendrie, August 10, 1973, transmitting item 4.7 above and discussing future action.

49. Memorandum to R. W. Klecker from Roger J. Mattson, September 7, 1973, transmitting an ANC internal memorandum which corrects the minutes of the June 21, 1973 meeting on pumps, i.e., Memorandum from R. F. Farman to W. A. Quill of Aero-jet Nuclear Company, dated 20 July 1973.

50. Letter to R. C. DeYoung from Romano Salvatori (Westinghouse), September 20, 1973, transmitting topical report WCAP-8163, "Reactor Coolant Pump Integrity In LOCA", in response to item 43. above.

C. GENERIC DOCUMENTS

51. Technical Safety Activities Report - December, 1975 - Division of Technical Review, transmitted by Robert E. Heinman's note dated January 5, 1976.

52. Memo Route Slip to EI&CS Branch from T. Ippolito, April 4, 1974, regarding evaluation of interruption of power to ESP au a during the accident sequence.

53. Memorandum to Joseph M. Hendrie from Thomas A. Ippolito, September 12, 1973, regarding a technical position on the application of the single failure criterion to manually-controlled electrically-operated valves.

54. Memo Route Slip to T. Ippolito from J. Hendrie, September 17, 1973, responding to item 53 above.

55. Memorandum to R. C. DeYoung and V. A. Moore from Victor Stello, Jr., October 1, 1973, transmitting "Technical Position on the Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves".

56. Letter to L. *Manning Muntzing* from W. Kerr, January 14, 1975 regarding "Locking Out of ECCS Power Operated Valves".

57. Note to Lester Rogers from A. Giambusso, October 24, 1973, regarding the need for and requirements on *instrumentation* to monitor 'post-accident *conditions.*

58. Memorandum to Victor Stello, Jr. from Thomas A. Ippolito, September 6, 1973, transmitting recommendations on "Design Improvements for Standard Plant Reviews".

59. Note to V. Stello from Thomas A. Ippolito, January 9, 1974, regarding "certain assumptions made in the analyses of the following accidents (which) are in violation with the established Staff's requirements".

60. Memorandum to Electrical, *Instrumentation* and Control Systems Branch Members from Thomas A. Ippolito, October 22, 1975, regarding responsibilities for evaluation of steam line break accidents.

61. Letter to Commissioner Gilinsky from S. H. Hanauer, March 13, 1975, entitled "Technical Issues". Dr. Hanauer discusses some technical issues he believes "to be important subjects for Commission consideration, although not necessarily in the immediate future".

Exhibit FP No. 11

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
OFFICE OF NUCLEAR MATERIAL SAFETY AND SAFEGUARDS
WASHINGTON D.C. 20555-0001

April 1, 2005

INFORMATION NOTICE 2005-07: RESULTS OF HEMYC ELECTRICAL RACEWAY FIRE BARRIER SYSTEM FULL SCALE FIRE TESTING

ADDRESSEES

All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel, and fuel facilities licensees.

PURPOSE

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to inform addressees of the results of Hemyc electrical raceway fire barrier system (ERFBS) full-scale fire tests. The Hemyc ERFBS did not perform for one hour as designed because shrinkage of the Hemyc ERFBS occurred during the testing. It is expected that recipients will review the information for applicability to their facilities and consider actions as appropriate to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

BACKGROUND

The Hemyc ERFBS, manufactured by Promatec, Inc., has been installed at nuclear power plants (NPPs) to protect circuits in accordance with regulatory requirements (Reference 1) and plant-specific commitments.

As a result of fire protection inspections, unresolved items (URIs) were opened at some nuclear power stations due to questions raised regarding the fire resistance capability of the Hemyc ERFBS (Reference 2). The Office of Nuclear Reactor Regulation (NRR) performed a review of the Hemyc ERFBS (Reference 3) and requested the NRC's Office of Nuclear Regulatory Research (RES) to perform confirmatory testing of this ERFBS. RES performed the testing at the Omega Point Laboratories in Elmendorf, Texas.

DISCUSSION

This information notice describes the results of the investigation of the fire resistance capability of the Hemyc ERFBS (Attachment 1). The NRC performed two ASTM E 119 furnace tests on a number of cable raceway types that are protected by the Hemyc ERFBS (with and without air gaps) in accordance with the Hemyc ERFBS test plan (see ADAMS Accession No. ML043210141 for a preliminary version of the test plan). The test plan provides

ML050890089

a detailed discussion of the assemblies and the thermocouple positions. The Hemyc ERFBS tests were performed for a period of 60-minutes each, followed by a hose stream test and post-test visual inspection of the ERFBS.

A bare No. 8 stranded copper conductor, instrumented with thermocouples every 6 inches along its length, was routed through each of the conduit and cable tray test specimens. Additional thermocouples were mechanically attached to the outer surfaces of the conduit test specimens and along the length of both side rails of the cable tray test specimens at 6-inch intervals. All results in Attachment 1 refer to the additional thermocouples attached to the outer surfaces of the conduits and cable trays unless otherwise stated.

Shrinkage of the Outer Covering

The Hemyc ERFBS is constructed of Hemyc mats consisting of Kaowool insulation inside an outer covering of Siltemp high-temperature fabric. The mats are machine-stitched at the factory to fit each electrical raceway installation. Hemyc mats that are directly wrapped around the electrical raceway use 2-inch-thick Kaowool. Hemyc mats that are installed over spaced frames to provide a 2-inch air gap between the Hemyc and the electrical raceway (for cable tray protection) use 1½-inch-thick Kaowool.

While Siltemp is a frequently used descriptor for the outer covering, and thus is used generically in this information notice, the material originally known as Siltemp is not now available commercially. The Promatec vendor manual references either Siltemp, Refrasil, or Alpha 600 as equivalent materials for the outer covering of the Hemyc ERFBS mats. This testing used the Refrasil brand fabric. The term "Siltemp" is most commonly used in the nuclear industry to describe the outer covering fabric of the Hemyc ERFBS mats. The NRC's preliminary testing indicates that the material density, thickness, and fabric weave are identical for both Siltemp and Refrasil.

During the fire testing, the outer layer of Siltemp consistently showed thermal shrinkage and change of color from tan to white. This shrinkage led to some gaps opening between the Hemyc ERFBS mats. NRC's preliminary findings indicate that the color change and shrinkage of both Siltemp and Refrasil materials are spatially uniform. Based on preliminary testing both Siltemp and Refrasil shrink approximately 8 percent during the ASTM E 119 furnace exposure.

Opening of the Joints

This testing examined the four most common methods of joining the Hemyc material into a complete ERFBS: (1) using stitched joints, (2) using minimum 6-inch collars over a joint, (3) using minimum 2-inch overlapping of the mats, and (4) using through bolts with fender washers. The Siltemp shrinkage led to the opening of each of the joint systems, which exposed the assembly (conduit, cable tray, junction box, air drop cable) to the furnace environment. For method (1), the shrinkage led to the seams being torn open. For method (2), the mats also experienced shrinkage, causing openings in the Hemyc ERFBS. It appeared that the 6-inch collar contracted and moved with one side of the material. For method (3), the 2-inch overlapping joints also opened. For method (4), the through-bolting of the Hemyc mats on the cable tray designs using the 2-inch air gap appeared to provide the most robust resistance to Siltemp shrinkage. However, due to this rigid fixed mounting of the Hemyc mats, the Siltemp

experienced tearing of the machine sewn seams and tearing of the Siltemp fabric. All but one assembly (conduit or cable tray) experienced temperatures capable of damaging plant cables (Reference 4).

Supports and Intervening Item Protection

With only the 3-inch thick Kaowool protection on supports as required by the vendor manual, the single point temperature rise of 325 °F was exceeded in 13 to 32 minutes. To prevent corruption of the thermal measurement data for the raceways because of potential thermal short-circuiting from structural supports, this program did not test the raceway and the structural supports together. Intervening metallic items would also be expected to permit the same temperature rise.

Significance of Results

The significance of the test results is that the Hemyc ERFBS did not perform for one hour as designed. Observations made during the testing, such as mat shrinkage and thermal shorts through the support protection, were not identified during previous testing of the material. Consequently, the Hemyc ERFBS does not provide the level of protection expected for a rated 1-hour fire barrier.

CONTACT

This information notice requires no specific action or written response. Please direct any questions about this matter to the technical contact(s) listed below or the appropriate NRR project manager.

/RA/
Patrick L. Hiland, Chief
Reactor Operations Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Technical Contact: Daniel Frumkin, NRR/DSSA
301-415-2280
E-mail: dxf1@nrc.gov

Attachment 1: Hemyc 1-Hour Fire-Rated Test Results

Note: NRC generic communications may be found on the NRC public Web site, http://www.nrc.gov, under Electronic Reading Room/Document Collections.

References:

1. Title 10 of the Code of Federal Regulations, Part 50, Appendix R, Section III.G.2

2. NRC Inspection Report 50-400/1999-13 (ADAMS Accession No. ML003685341); NRC Inspection Reports 50-369/2000-09 and 50-370/2000-09 (ADAMS Accession No. ML003778709)

3. NRR Response to Task Interface Agreement (TIA) 99-028, "Shearon Harris Nuclear Power Plant, Unit 1 - Resolution of Pilot Fire Protection Inspection Fire Barrier Qualification Issues," dated August 1, 2000 (ADAMS Accession No. ML003736721)

4. Inspection Manual Chapter 0609, Appendix F, Fire Protection Significance Determination Process, Attachment 7, page F7-2

Hemyc 1-Hour Fire-Rated Test Results
Conduit , Supports & Junction Box

Raceway	Time to $\Delta T_{ave} \geq 250°F$ (minutes)	Time to Single Point $\Delta T > 325°F$ (minutes)	Max. Temp. Bare #8 @ 1 hour[1] (°F)	Joint Opening[2] Yes/No
1" Conduit (1E) (Empty)	46	42	1013	Yes
1" Conduit (1F) 1.02 lb./linear foot (lin.ft.) Cable Fill	44	34	1177	Yes
2 ½ " Conduit (1C) (Empty)	48	41	709	Yes
2 ½ " Conduit (1D) 5.85 lb./lin.ft. Cable Fill	51	38	446	Yes
4" Conduit (1A) (Empty)	49	33	865	Yes
4" Conduit (1B) 14.84 lb./lin.ft. Cable Fill	57	43	199	Yes
Junction Box 18" x 24" x 8"	17	15	NA	Yes
Unistrut Support[3]	NA	22 - 32	NA	NA
2" Tube Steel Support[3]	NA	13 - 25	NA	NA

Hemyc 1-Hour Fire-Rated Test Results
Cable Tray, Junction Box, & Airdrop

Raceway	Right Side Tray Rail $\Delta T_{ave} \geq$ 250°F (minutes)	Right Side Tray Rail Single Point ΔT > 325°F (minutes)	Left Side Tray Rail $\Delta T_{ave} \geq$ 250°F (minutes)	Left Side Tray Rail Single Point ΔT > 325°F (minutes)	Bare #8 $\Delta T_{ave} \geq$ 250°F (minutes)	Bare #8 Single Point ΔT > 325°F (minutes)	Bare #8 Max. Temp. @ 1 hour (°F)	Joint Opening[2] Yes/No
12" Cable Tray Empty, (2A) Direct Attachment	36	34	27	18	32	32	1260	Yes
12" Cable Tray Empty, (2B) 2" Air Gap	37	35	38	35	33	34	1002	Yes
36" Cable Tray Empty, (2C) Direct Attachment	41	39	34	33	35	35	1330	Yes
36" Cable Tray Empty, (2D) 2" Air Gap	32	31	33	32	28	27	1117	Yes
Air Drop, (2E) Direct Attachment	NA	NA	NA	NA	35	32	1712	Yes
Air Drop, (2F) 2" Air Gap	NA	NA	NA	NA	32	28	1411	Yes
18" x24" x 8"Junction Box,(2G) Direct Attachment with Bands[4]	31	32	NA	NA	NA	NA	NA	Yes

Notes:

1. The temperatures recorded on the Bare No. 8 conductor may not be indicative of the actual temperature inside the assembly for two reasons. First, to insure the integrity of the thermocouple's jacket and insulation during installation, the instrumented Bare No. 8 conductor was located in the center of the cable; therefore it may not have been exposed to the highest temperature within the conduit. The second reason was that the joints opened during the testing, producing local hot spots on the interior of the raceway that may or may not have been picked up by the Bare No. 8 conductor.

2. All Hemyc ERFBSs experienced some thermal shrinkage of the outer Siltemp covering. As a result, some joints opened and exposed the conduits or cable trays to the furnace environment at various points during the test.

3. The time provided for the structural supports was determined to be the time when the single point temperature rise (ΔT) exceeded 325 °F at a distance 3 inches into the Hemyc insulation protecting the structural steel. Three inches is the minimum structural support protection recommended in the vendor manual.

4. The junction box average temperature is the average across all thermocouples mounted on the outside of the box's surface. The single-point temperature is also measured on the external surface of the junction box.

Exhibit FP No. 12

December 9, 2003

POGO Letter to NRC Chairman Niles Diaz

December 9, 2003

Chairman Niles J. Diaz
Nuclear Regulatory Commission
11555 Rockville Pike
Rockville, MD 20852

Via facsimile: (301) 415-1757

Dear Chairman Diaz,

As you recall, in September I wrote to you to respond to your letter to the New York Congressional delegation and local politicians claiming that this summer's force-on-force test at Indian Point had shown a "strong defensive strategy and capability." The NRC responded to my letter by demanding that POGO not make the letter public, claiming that it contained homeland security sensitive and "safeguarded" material. The NRC threatened us with civil and criminal sanctions were we to continue to make public either our letter or any of the sensitive material it allegedly contained. The NRC also took the position that it had no obligation to identify the passages in the letter that it claimed were sensitive. As a result, the NRC's initial position was that any effort by POGO to criticize the lack of security at Indian Point threatened the release of safeguards information and thus POGO did so at the risk of criminal prosecution. We believe that the agency took this position to stifle legitimate criticism of the agency by POGO.

We did not let the matter end there. POGO retained counsel and threatened legal action against the NRC for stifling POGO's speech. Ultimately, the agency backed down and agreed to identify the portions of our September letter that were in the agency's view problematic. We appreciate the agency's willingness to engage POGO on this issue and believe that our discussions were helpful to all concerned. What follows is a redraft of our original letter. We look forward to your prompt response.

Our primary concern is that the way the force-on-force (FOF) tests were conducted do not give you the ability to reassure the public that the Indian Point security force has been proven capable to defend that facility against a credible terrorist attack. After a thorough review of the test of security at Indian Point, we continue to have the following concerns:

Dumbed-Down Design Basis Threat (DBT) – It has been widely reported in the press1 that prior to 9/11, nuclear power plants were required to have defenses designed to protect against only a ridiculously small attacking force – three terrorists. In contrast, the intelligence community generally believes that terrorists would attack a target with a squad-sized force, which in the Army special forces is 12 and the Navy Seals is 14. In other words, the NRC would need to at least quadruple its old DBT.

Having interviewed a number of people who have reviewed the NRC's new DBT, we do not believe that it is even close to reaching the 12 to 14 level we believe is appropriate. Representatives of other federal agencies have told POGO that the NRC's new DBT remains inadequate.

The NRC argues that the new DBT is the largest threat against which a private security force can be expected to defend. This rationale is backwards and conflates two separate considerations – what is the size of the threat and what should the nuclear power industry be required to do to in the face of such threats. The NRC policy decision to limit the size of the DBT (under terrific pressure from the nuclear industry and its friends in Congress) was based mainly on its assessment of what is reasonable to ask of a private force. But that approach ignores the most fundamental question: what is the credible threat against the facilities? The size of the DBT must be based on that threat. Furthermore, NRC's justification of its too-low DBT rings hollow, as the Department of Energy (DOE) also relies on a private security force, yet at some facilities, DOE claims to protect its facilities against twice as many terrorists as the NRC does.

Under Use of Readily-Available Lethal Weapons – It is well known in security circles that there are weapons that are available to terrorists that can penetrate bullet-resistant enclosures (BREs),

which are quasi-guard towers. BREs are included in the defensive strategy of a number of nuclear power plants, including Indian Point. Some time ago, the Department of Energy abandoned the use of its state-of-the-art guard towers (which are far more robust than most BREs) because of their vulnerability to readily-available weapons. Indian Point officers have been aware of the controversies surrounding BREs and have brought their concerns not only to Entergy, but also to the NRC Region I, with no response at all. Several years ago, the DOE developed a classified official Adversary Capabilities List which includes weapons and explosives that are readily available to terrorist groups. The NRC should review this list and ensure its Design Basis Threat includes them. For example, .50 caliber sniper rifles (which have been available since World War I) and Armor-Piercing Incendiary rounds (which are available in gun shops for $1 per round) made the DOE guard towers so vulnerable they were abandoned. Other weapons were also of concern, including the rocket-propelled grenades which have been used frequently by near-children around the world in war-torn countries, with great success against hardened targets.

Unrealistic Timing and Location of Attack – It appears the NRC conducted the three FOF tests at Indian Point during the daylight at the beginning of the night shift, and began at least two of the tests in the owner-controlled area. There are several problems with this:

- The security force being tested had just come on duty and was not yet fatigued by a 12-hour shift, hours typically worked by Indian Point security officers five to six days a week.
- The security officers knew within the hour that the test was to begin, as the day shift was held over an extra hour to cover as a shadow force so that the night shift could be tested at the beginning of their shift.
- It is widely believed in the intelligence community that no one will attack during daylight, as it is to the attacker's advantage to have the cover of darkness. Despite this, all three FOF tests occurred between 4-6 pm. Furthermore, in two of the three tests, the mock terrorists were required to cross open fields in broad daylight in order to reach the protected area, making it that much easier for them to be observed by the security officers.
- The mock terrorists attacked from only one entry point. In addition, the NRC and Entergy agreed that, if the attackers were successful in reaching the protected area fences, there would be a halt in the action and the adversaries would be brought inside of the fences (to prevent any actual damage to the fences during the exercise) – making it perfectly obvious from where the attack will be coming. POGO had previously alerted the NRC to a particular vulnerability involving the fences at most nuclear facilities and was assured that this vulnerability would be taken into account in future FOF tests. However, it was does not appear to have been taken into account during the Indian Point FOF.

Amateur Mock Terrorists – A terrorist group has advantages that cannot be replicated in even the best mock attack FOF. However, the following limitations could have been partially ameliorated by the NRC, but were not:

- **No Surprise.** The security force knew for months in advance that this test was going to occur, training specifically for the approved scenarios. They even knew within minutes that the test was to occur, because of all the visiting dignitaries and the fact that they had strapped on Multiple Integrated Laser Engagement System (MILES) equipment.
- **No Violence of Action.** During a mock FOF there is no real danger – no live ammo, no colleagues dying or being maimed or any other adverse impact that would normally create chaos and in some cases cause the protective forces to panic. As a result, security forces develop "MILES bravery."
- **Safety First.** The FOF tests are not conducted at high speed because of the overriding safety concerns. Therefore, people and vehicles are not going full tilt the way they would during a real terrorist attack, giving the protective forces time to pause to make decisions –

time that they wouldn't have in a real life situation. Safety was also used as the reason for not conducting the tests at night. Sources told us that Entergy was worried participants could trip over rocks or step on snakes.

- **No Trained Adversaries.** The mock terrorists were security officers from another nuclear plant who had no training as adversaries. This training is critically important because it teaches the mock terrorist how to think and act offensively, as a real terrorist would, rather than defensively as a security guard would. Here again, both DOE and the military use trained adversaries to test their security forces.

The Security Forces Are On Their Own – It should be recognized that although the exercise was observed by the State Police and FBI, these law enforcement entities cannot respond to an attack with SWAT capability before it is too late. Insofar as we know, these response times have not been tested at Indian Point. But tests at other facilities have shown that an attack is generally won or lost in between three and eight minutes, while it generally takes an hour or two for SWAT teams to respond.

Poor Planning: Lives at Risk – One of the FOF tests was quickly aborted when Coast Guard personnel, who had not been previously informed that the test was to occur, threatened to use their live ammo against the mock attackers. It is unacceptably poor planning to allow this kind of lack of professionalism, putting lives at risk.

Recommendations:

The NRC should:

- Not allow so much advanced notice and training for the FOF – two weeks is sufficient;
- Make the window of attack much less obvious, therefore making it unclear to the participants at what time during the shift the test will take place;
- Administer most of the tests when it is dark;
- Use trained adversary teams from the military or develop its own trained adversary team;
- Conduct computer simulations – either Joint Tactical Simulations (JTS) or Joint Conflict Adversary Tactical Simulations (JCATS) – used by the military and Department of Energy for years. These computer programs simulate the movement of personnel through architecturally- and terrain-accurate models of the facility. This preparation helps the security forces develop the best strategies for defeating any number of possible attacks;
- Include the use of simulated rocket-propelled grenades, sniper rifles with .50 caliber armor-piercing incendiary rounds, gas, smoke and other commonly used weapons and diversionary devices if they are not currently in the DBT; and
- Address the serious communications breakdowns that occurred during the recent Indian Point FOF.

These issues are obviously very serious and need to be addressed promptly. We look forward to your response.

Sincerely,

Danielle Brian
Executive Director

cc Roy Zimmerman

1. *U.S. News & World Report*, September 17 2001; *Chicago Tribune*, July 12, 2002; The *Boston Globe*, May 14, 2002; *Bulletin of the Atomic Scientists*, January 1, 2002; *New York Times* Magazine, May 26, 2002.

Exhibit FP No. 13

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CRS Report for Congress

Received through the CRS Web

Nuclear Power Plants: Vulnerability to Terrorist Attack

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Summary

Protection of nuclear power plants from land-based assaults, deliberate aircraft crashes, and other terrorist acts has been a heightened national priority since the attacks of September 11, 2001. The Nuclear Regulatory Commission (NRC) has strengthened its regulations on nuclear reactor security, but critics contend that implementation by the industry has been too slow and that further measures are needed. Several provisions to increase nuclear reactor security are included in the Energy Policy Act of 2005, signed August 8, 2005. The new law requires NRC to conduct "force on force" security exercises at nuclear power plants at least once every three years and to revise the "design-basis threat" that nuclear plant security forces must be able to meet, among other measures. This report will be updated as events warrant.

Nuclear power plants have long been recognized as potential targets of terrorist attacks, and critics have long questioned the adequacy of the measures required of nuclear plant operators to defend against such attacks. Following the September 11, 2001, attacks on the Pentagon and the World Trade Center, the Nuclear Regulatory Commission (NRC) began a "top-to-bottom" review of its security requirements. On February 25, 2002, the agency issued "interim compensatory security measures" to deal with the "generalized high-level threat environment" that continued to exist, and on January 7, 2003, it issued regulatory orders that tightened nuclear plant access. On April 29, 2003, NRC issued three orders to restrict security officer work hours, establish new security force training and qualification requirements, and increase the "design basis threat" that nuclear security forces must be able to defeat.

Security Regulations

Under the regulations in place prior to the September 11 attacks, all commercial nuclear power plants licensed by NRC must be protected by a series of physical barriers and a trained security force. The plant sites are divided into three zones: an "owner-controlled" buffer region, a "protected area," and a "vital area." Access to the protected area is restricted to a portion of plant employees and monitored visitors, with stringent

access barriers. The vital area is further restricted, with additional barriers and access requirements. The security force must comply with NRC requirements on pre-hiring investigations and training.[1]

Design Basis Threat. The severity of attacks to be prepared for are specified in the form of a "design basis threat" (DBT). One of NRC's April 2003 regulatory orders changed the DBT to "represent the largest reasonable threat against which a regulated private guard force should be expected to defend under existing law," according to the NRC announcement. The details of the revised DBT, which took effect October 29, 2004, were not released to the public.

NRC requires each nuclear power plant to conduct periodic security exercises to test its ability to defend against the design basis threat. In these "force on force" exercises, monitored by NRC, an adversary force from outside the plant attempts to penetrate the plant's vital area and damage or destroy key safety components. Participants in the tightly controlled exercises carry weapons modified to fire only blanks and laser bursts to simulate bullets, and they wear laser sensors to indicate hits. Other weapons and explosives, as well as destruction or breaching of physical security barriers, may also be simulated. While one squad of the plant's guard force is participating in a force-on-force exercise, another squad is also on duty to maintain normal plant security. Plant defenders know that a mock attack will take place sometime during a specific period of several hours, but they do not know what the attack scenario will be. Multiple attack scenarios are conducted over several days of exercises.

Full implementation of the force-on-force program coincided with the effective date of the new DBT in late 2004. Standard procedures and other requirements have been developed for using the force-on-force exercises to evaluate plant security and as a basis for taking regulatory enforcement action. Many tradeoffs are necessary to make the exercises as realistic and consistent as possible without endangering participants or regular plant operations and security. Each plant is required to conduct NRC-monitored force-on-force exercises once every three years.

NRC required the nuclear industry to develop and train a "composite adversary force" comprising security officers from many plants to simulate terrorist attacks in the force-on-force exercises. However, in September 2004 testimony, the Government Accountability Office (GAO) criticized the industry's selection of a security company that guards about half of U.S. nuclear plants, Wackenhut, to also provide the adversary force. In addition to raising "questions about the force's independence," GAO noted that Wackenhut had been accused of cheating on previous force-on-force exercises by the Department of Energy.[2]

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[1] General NRC requirements for nuclear power plant security can be found at 10 CFR 73.55.

[2] Government Accountability Office. *Nuclear Regulatory Commission: Preliminary Observations on Efforts to Improve Security at Nuclear Power Plants.* Statement of Jim Wells, Director, Natural Resources and Environment, Government Accountability Office, to the Subcommittee on National Security, Emerging Threats, and International Relations, House Committee on Government Reform. September 14, 2004. p. 14.

Congress imposed statutory requirements for the DBT and force-on-force exercises in the Energy Policy Act of 2005, signed August 8, 2005. The act requires that each nuclear plant undergo force-on-force exercises at least once every three years (NRC's current policy), that the exercises simulate the threats in the DBT, and that NRC "mitigate any potential conflict of interest that could influence the results of a force-on-force exercise, as the Commission determines to be necessary and appropriate."

The new law requires NRC to revise the DBT within 18 months, after considering a wide variety of potential modes of attack (physical, chemical, biological, etc.), the potential for large attacks by multiple teams, potential assistance by several employees inside a facility, the effects of large explosives and other modern weaponry, and other specific factors.

Emergency Response. After the 1979 accident at the Three Mile Island nuclear plant near Harrisburg, PA, Congress required that all nuclear power plants be covered by emergency plans. NRC requires that within an approximately 10-mile Emergency Planning Zone (EPZ) around each plant the operator must maintain warning sirens and regularly conduct evacuation exercises monitored by NRC and the Federal Emergency Management Agency (FEMA). In light of the increased possibility of terrorist attacks that, if successful, could result in release of radioactive material, critics have renewed calls for expanding the EPZ to include larger population centers.

Another controversial issue regarding emergency response to a radioactive release from a nuclear power plant is the distribution of iodine pills. A significant component of an accidental or terrorist release from a nuclear reactor would be a radioactive form of iodine, which tends to concentrate in the thyroid gland of persons exposed to it. Taking a pill containing non-radioactive iodine before exposure would prevent absorption of the radioactive iodine. Emergency plans in many states include distribution of iodine pills to the population within the EPZ, which would protect from exposure to radioactive iodine, although giving no protection against other radioactive elements in the release. NRC in 2002 began providing iodine pills to states requesting them for populations within the 10-mile EPZ.

Nuclear Plant Vulnerability

Operating nuclear reactors contain large amounts of radioactive fission products which, if dispersed, could pose a direct radiation hazard, contaminate soil and vegetation, and be ingested by humans and animals. Human exposure at high enough levels can cause both short-term illness and death, and longer-term deaths by cancer and other diseases.

To prevent dispersal of radioactive material, nuclear fuel and its fission products are encased in metal cladding within a steel reactor vessel, which is inside a concrete "containment" structure. Heat from the radioactive decay of fission products could melt the fuel-rod cladding even if the reactor were shut down. A major concern in operating a nuclear power plant, in addition to controlling the nuclear reaction, is assuring that the core does not lose its coolant and "melt down" from the heat produced by the radioactive fission products within the fuel rods. Therefore, even if plant operators shut down the reactor as they are supposed to during a terrorist attack, the threat of a radioactive release would not be eliminated.

Commercial reactor containment structures — made of steel-reinforced concrete several feet thick — are designed to prevent dispersal of most of a reactor's radioactive material in the event of a loss of coolant and meltdown. Without a breach in the containment, and without some source of dispersal energy such as a chemical explosion or fire, the radioactive fission products that escaped from the melting fuel cladding mostly would remain where they were. The two major meltdown accidents that have taken place in power reactors, at Three Mile Island in 1979 and at Chernobyl in the Soviet Union in 1986, illustrate this phenomenon. Both resulted from a combination of operator error and design flaws. At Three Mile Island, loss of coolant caused the fuel to melt, but there was no fire or explosion, and the containment prevented the escape of substantial amounts of radioactivity. At Chernobyl, which had no containment, a hydrogen explosion and a fierce graphite fire caused a significant part of the radioactive core to be blown into the atmosphere, where it contaminated large areas of the surrounding countryside and was detected in smaller amounts literally around the world.

Vulnerability from Air Attack. Nuclear power plants were designed to withstand hurricanes, earthquakes, and other extreme events, but attacks by large airliners loaded with fuel, such as those that crashed into the World Trade Center and Pentagon, were not contemplated when design requirements were determined. A taped interview shown September 10, 2002, on Arab TV station al-Jazeera, which contains a statement that Al Qaeda initially planned to include a nuclear plant in its 2001 attack sites, intensified concern about aircraft crashes.

In light of the possibility that an air attack might penetrate the containment building of a nuclear plant, some interest groups have suggested that such an event could be followed by a meltdown and widespread radiation exposure. Nuclear industry spokespersons have countered by pointing out that relatively small, low-lying nuclear power plants are difficult targets for attack, and have argued that penetration of the containment is unlikely, and that even if such penetration occurred it probably would not reach the reactor vessel. They suggest that a sustained fire, such as that which melted the structures in the World Trade Center buildings, would be impossible unless an attacking plane penetrated the containment completely, including its fuel-bearing wings.

Recently completed NRC studies "confirm that the likelihood of both damaging the reactor core and releasing radioactivity that could affect public health and safety is low," according to NRC Chairman Nils Diaz. However, NRC is considering studies of additional measures to mitigate the effects of an aircraft crash.[3]

Spent Fuel Storage. Radioactive "spent" nuclear fuel — which is removed from the reactor core after it can no longer efficiently sustain a nuclear chain reaction — is stored in pools of water in the reactor building or in dry casks elsewhere on the plant grounds. Because both types of storage are located outside the reactor containment structure, particular concern has been raised about the vulnerability of spent fuel to attack by aircraft or other means. Spent fuel pools and dry cask storage facilities are subject to NRC security requirements.

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[3] Letter from NRC Chairman Nils J. Diaz to Secretary of Homeland Security Tom Ridge, September 8, 2004.

The primary concern is whether terrorists could breach the thick concrete walls of a spent fuel pool and drain the cooling water, which could cause the spent fuel's zirconium cladding to overheat and catch fire. A report released in April 2005 by the National Academy of Sciences (NAS) found that "successful terrorist attacks on spent fuel pools, though difficult, are possible," and that "if an attack leads to a propagating zirconium cladding fire, it could result in the release of large amounts of radioactive material." NAS recommended that the hottest spent fuel be interspersed with cooler spent fuel to reduce the likelihood of fire, and that water-spray systems be installed to cool spent fuel if pool water were lost. The report also called for NRC to conduct more analysis of the issue and consider earlier movement of spent fuel from pools into dry storage.[4]

Both the House- and Senate-passed versions of the FY2006 Energy and Water Development appropriations bill (H.R. 2419, H.Rept. 109-86, S.Rept. 109-84) would provide $21 million for NRC to carry out the NAS recommendations. The House Appropriations Committee was particularly critical of NRC's actions on spent fuel storage security: "The Committee expects the NRC to redouble its efforts to address the NAS-identified deficiencies, and to direct, not request, industry to take prompt corrective actions."

Regulatory and Legislative Proposals

Critics of NRC's security measures have demanded both short-term regulatory changes and legislative reforms.

A fundamental concern was the nature of the DBT, which critics contended should be increased to include a number of separate, coordinated attacks. Critics also contended that nearly half of the plants tested in NRC-monitored mock attacks before 9/11 failed to repel even the small forces specified in the original DBT, a charge that industry sources vigorously denied. Critics also pointed out that licensees are required to employ only a minimum of five security personnel on duty per plant, which they argue is not enough for the job.[5] Nuclear spokespersons responded that the actual security force for the nation's 65 nuclear plant sites numbers more than 5,000, an average of about 75 per site (covering multiple shifts). Nuclear plant security forces are also supposed to be aided by local law enforcement officers if an attack occurs.

In February 2002, NRC implemented what it called "interim compensatory security measures," including requirements for increased patrols, augmented security forces and capabilities, additional security posts, installation of additional physical barriers, vehicle checks at greater stand-off distances, enhanced coordination with law enforcement and military authorities, and more restrictive site access controls for all personnel. The further

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[4] National Academy of Sciences, Board on Radioactive Waste Management, *Safety and Security of Commercial Spent Nuclear Fuel Storage, Public Report* (online version), released April 6, 2005.

[5] 10 CFR 73.55 (h)(3) states: "The total number of guards, and armed, trained personnel immediately available at the facility to fulfill these response requirements shall nominally be ten (10), unless specifically required otherwise on a case by case basis by the Commission; however, this number may not be reduced to less than five (5) guards."

orders issued April 29, 2003, expanded on the earlier measures, including revising the DBT, which critics continue to describe as inadequate. Continuing congressional concerns resulted in the new criteria in the Energy Policy Act of 2005 for further DBT revisions.

Because of the growing emphasis on security, NRC established the Office of Nuclear Security and Incident Response on April 7, 2002. The office centralizes security oversight of all NRC-regulated facilities, coordinates with law enforcement and intelligence agencies, and handles emergency planning activities. Force-on-force exercises are an example of the office's responsibilities. On June 17, 2003, NRC established the position of Deputy Executive Director for Homeland Protection and Preparedness, whose purview includes the Office of Nuclear Security and Incident Response.

Legislation. Since the 9/11 attacks, numerous legislative proposals, including some by NRC, have focused on nuclear power plant security issues. Several of those ideas, such as the revision of the design-basis threat and the force-on-force security exercises, were included in the Energy Policy Act of 2005, which also includes:

- assignment of a federal security coordinator for each NRC region;
- backup power for nuclear plant emergency warning systems;
- tracking of radiation sources;
- fingerprinting and background checks for nuclear facility workers;
- authorizing use of firearms by nuclear facility security personnel (preempting some state restrictions);
- authorizing NRC to regulate dangerous weapons at licensed facilities;
- extending penalties for sabotage to cover nuclear facilities under construction;
- requiring a manifest and personnel background checks for import and export of nuclear materials; and
- requiring NRC to consult with the Department of Homeland Security on the vulnerability to terrorist attack of locations of proposed nuclear facilities before issuing a license.

A number of legislative proposals introduced since 9/11 to increase nuclear plant security were not included in the new law, including the creation of a federal force within the NRC to replace the private guards at nuclear power plants, requiring emergency planning exercises within a 50-mile radius around each nuclear plant, and stockpiling iodine pills for populations within 200 miles of nuclear plants. Other measures proposed but not enacted include a task force to review security at U.S. nuclear power plants and a federal team to coordinate protection of air, water, and ground access to nuclear power plants.

Exhibit FP No. 14

March 27, 2007

Re: NRC Proposed Rule: Power Reactor Security Requirements (RIN 3150-AG63)

Annette Vietti-Cook, Secretary
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Attn: Rulemakings and Adjudications Staff
Submitted via e-mail to SECY@nrc.gov

COUNCIL ON INTELLIGENT ENERGY & CONSERVATION POLICY (CIECP) COMMENTS TO PROPOSED RULE 10 CFR PARTS 50, 72 AND 73 REGARDING POWER REACTOR SECURITY REQUIREMENTS AT LICENSED NUCLEAR FACILITIES

Nearly six years after September 11, 2001, the 103 civilian nuclear reactors in the United States are still not in a position to repel attacks by adversaries with capabilities commensurate with those of either the 9/11 terrorists or with enemies of the United States currently operative on the world stage. The present Power Reactor Security Requirements (PRSR) thus fall far short of the actual threat level faced by the U.S. today, much less the escalated level the nation will face as nations such as Russia, China and Iran improve and export nuclear engineering expertise. Indeed, as numerous security experts have pointed out, a terrorist group with access to sympathetic nuclear scientists and engineers would have sufficient sophistication to target the critical systems and weak links of nuclear reactors. The assistance that Pakistani nuclear scientists reportedly offered to Al Qaeda illustrates this threat.

Recent National Intelligence Estimates and National Intelligence Council Reports describe the terrorist threat to the U.S. as real and as having no sign of abatement for many years to come. These reports further warn of a new class of "professionalized" terrorists -in part created by the Iraq war- who must be expected to have strong technical skills and English language proficiency. Such individuals should, in the future, be expected to become major players in international terrorism.

Al Qaeda and other terrorist groups have shown extraordinary tactical ingenuity and a complete lack of reverence for human life. Further there is ample evidence that U.S. nuclear power plants, particularly those sited near metropolitan areas, are viewed as attractive terrorist targets. Notably, the 9/11 Commission learned that the original plan for a terrorist spectacular was for a larger strike, using more planes, and including an attack on nuclear power plants. In an Al-Jazeera broadcast in 2002, one of the planners of 9/11 said that a nuclear plant was the initial target considered. We also know from the 9/11 Commission's investigation that, even after the plot was scaled down, when Mohammed Atta was conducting his surveillance flights he spotted a nuclear power plant (unidentified by name, but obviously the Indian Point nuclear power plant) and came close to redirecting the strike. National Research Council analyses and post-9/11 intelligence has also indicated that the U.S. nuclear infrastructure is viewed as an alluring target for a future terrorist spectacular. As the Chairman of the National Intelligence Council stated in 2004, nuclear power plants "are high on Al Qaeda's targeting list," adding that the methods of Al Qaeda and other terrorist group may be "evolving."

There is, thus, every reason to believe that a sizable, well-planned and orchestrated military operation against a U.S. nuclear facility is well within both present and near-future terrorist intent and capability. In view of these realities, the current proposed PRSR is utterly inadequate.

Consequently, the COUNCIL ON INTELLIGENT ENERGY & CONSERVATION POLICY (CIECP) urges the NRC to address the following realities in its PRSR:

ACTIVE INSIDERS

The voluminous number of security breaches which have occurred at critical infrastructure, including nuclear weapons and power facilities after 9/11 (such as the 16 foreign-born construction workers who

were able to gain access to the Y-12 nuclear weapons plant with falsified documentation) demonstrates that nuclear "insiders" must be deemed potential active participants in an attack.

This threat is significantly augmented by nuclear power plant operators' increasing outsourcing of on-site work in order to cut costs.

Contractor oversight failures have been documented by the NRC. For example a December 22, 2003 NRC Special Inspection Report on the Indian Point Nuclear Generating Station in Buchanan, New York (Indian Point) operated by Entergy Nuclear Northeast (Entergy) notes "the common theme of a lack of direct contractor oversight and quality control measures, along with the absence of Entergy subject matter experts to independently assess contracted work activities...." Critically, the risk of sabotage is elevated at all power plants during periods of refueling and major construction work when hundreds of outside contract workers have site access.

The active participation of insiders, including contract workers, in a terrorist offensive need not take place during the time of attack. It may occur days or even many months prior to an attack. In addition to actions such as surveillance of plant schematics, security features and protocols, pre-attack participation may involve the sabotage of critical instrumentation, computers, piping, electronic systems or any number of other components, where such sabotage would likely not be discovered prior to an emergency event.

COMPUTER SYSTEM COMPROMISE

Nuclear power plant computer systems, like those of other critical infrastructure, are subject to a range of vulnerabilities, including power outages, attacks by malicious hackers, viruses and worms. Compromise of integrity may also occur at the level of software development via backdoors written into code or the implantation of logic bombs programmed to shut down a safety system at a particular time.

Many terrorist networks have the resources and technical savvy to wreak havoc. For example, the alleged terrorist, Muhammad Naeem Noor Khan, picked up in Pakistan in 2004, and believed to have links with Al Qaeda, is a computer engineer.

The fact that U.S. nuclear reactors are not impregnable was demonstrated by the penetration of the Slammer worm into the Davis-Besse nuclear facility. That intrusion disabled a safety monitoring system for nearly 5 hours. In addition, computer hackers have broken into U.S. Department of Energy computers. Some of such intrusions were root-level compromises, indicating that hackers had enough access to install viruses.

Computers at nuclear power stations are also vulnerable to acts of sabotage against off-site power transmission, as was evidenced at Indian Point during the 2003 blackout which struck the Northeast. At Indian Point, various computer systems had to be removed from service, including the Critical Function Monitoring System, the Local Area Network, the Safety Assessment System/Emergency Data Display System, the Digital Radiation Monitoring System and the Safety Assessment System.

It is, accordingly, a matter of pressing importance that the NRC engage independent experts to develop a comprehensive computer vulnerability and cyber-attack threat assessment. Such an assessment must evaluate the vulnerability of the full range of nuclear power plant computer systems and the potential consequences of such vulnerabilities. The PRSR must incorporate such findings and include a protocol for quickly detecting such an attack and recovering key computer functions in the event of an attack.

CHEMICAL WEAPONS

The PRSR must fully address the potential consequences of the use of toxic chemicals as part of an attack scenario. There are numerous agents that can be deployed with almost instantaneous effect and can immobilize targets via paralysis, convulsions, blinding, suffocation or death. Such agents could be employed as part of the initialization strategy. For, example, a truck or even large SUV filled with chlorine, boron trifluoride, hydrofluoric acid, liquid ammonia, or any number of other agents could be crashed into a perimeter barrier, with the resulting fumes killing or disabling plant personnel guarding the outdoor area of the facility.

Chemical agents could also be introduced surreptitiously into building ventilation systems. They may also be used strategically to neutralize workers endeavoring to maintain control of the situation.

Many such agents are easy to make and do not require sophisticated delivery systems. Some can be carried in coffee mugs or in vials within body cavities. Phenarsazine chloride, an arsenic derivative, can be transported in minute quantities, even as a powder that can be dusted on paper. It is lethal if burned and even a spoonful can cause immediate extreme irritation of the eyes and breathing passages. A chemical like chloroform ascitone methanol can be transported on filter paper, then combined with a heat source to create an explosion.

CONVENTIONAL WEAPONRY

Intelligence and military analysts have repeatedly warned that extremists in Iraq, the tribal areas of Pakistan and elsewhere are currently developing a high level of military skill and experience. This reality underscores the need for nuclear plants to be able to defend against attackers utilizing the full range of potential weaponry that terrorists are known to be capable of using, including heavy caliber automatic weapons; sniper rifles; shoulder-fired rockets; mortars; platter charges; anti-tank weaponry; bunker busters; shaped charges; rocket-propelled grenades; and high-power explosives.

Numerous weapons systems posing a threat to even the best trained and equipped civilian guard force, as well as to on-site installations, are readily available and easy to transport. To wit:

o Assault rifles and other rapid-fire battlefield weapons such as AK-47's, Uzi's and TEC-9's are freely available in the U.S. A weapon like the SKS 7.62-millimenter semiautomatic assault rifle can be purchased for under $200. In 2005 the Government Accountability Office reported that 47 individuals on a federal terrorism watch list were actually permitted to legally buy guns in 2004.

o A standard M-24 sniper rifle with day and night scope can be carried in a canvas bag and fires 7.62-millimeter ammunition targeting up to 3000 feet

o A .50-caliber Barrett rifle, which can be purchased for $1000 on the internet, weighs a mere 30 lbs and can hit targets up to 6000 feet away with armor-piercing bullets that can blow a hole through a concrete bunker, bring down a helicopter or pierce an armored vehicle.

o A rocket propelled grenade launcher is re-loadable, can fire at the speed of 400 feet per second and can blow a vehicle into the air.

o A TOW missile is an accessible form of military hardware used in over 40 countries and can be fired from a launcher on a flatbed truck. A 1998 test TOW fired into a nuclear waste transport cask (which is more robust than many on-site nuclear waste storage casks) blew out a hole the size of a grapefruit. The Kornet-E missile, developed by the Soviets and sold to Iraq, can travel over 3 miles and cut through over 3 feet of steel. The world's arms market is awash in thousands of Milan missiles. The 60-70 lb Milan missile system has an effective range of over 5000 feet and can blow a hole through more than 3 feet of armor plate.

o The deployment of increasingly powerful and sophisticated explosives, including shaped charges and explosively formed penetrators (or E.F.P.s) by terrorists and insurgents in Iraq show that the explosives use capabilities of enemies of the United States should not be underestimated. Notably, the 18 men arrested in Australia in November 2005, and believed to have been planning an attack on an Australian nuclear reactor, had allegedly been stockpiling materials used to make the explosive triacetone triperoxide, or TATP. Terrorists targeting a U.S. nuclear power plant may very well be able to draw on expertise developed during the Iraq insurgency as well as military experts and rocket scientists from the former Iraq government or from hostile nations such as Iran. In addition, the strategic utility of explosives is magnified when bombers are willing to blow themselves up. Suicide bombers able to gain access to the internal areas of a nuclear power plant during the course of an attack could cause untold destruction.

o Perhaps the most intractable military hardware threat is posed by shoulder-fired missiles such as

Stingers, SA-7's, SA-14's and SA-18's. An estimated 500,000 such systems are scattered throughout the world and have been found in the possession of at least 27 terrorist or guerrilla groups. Some can be bought easily on the black market for as little as several thousand dollars each. Critically, shoulder-fired missiles are easy to operate (Al Qaeda training videos offer instruction) and are designed for portability, typically being 5-6 feet long and weighing 35 lbs. They can be transported by and fired from a van, S.U.V., pickup truck or recreational boat. Even a single terrorist armed with a shoulder-fired missile can cause immediate and substantial damage to a targeted structure. Traveling at more than 1,500 miles per hour, a typical shoulder-launched missile has a range of over 12,000 feet. If the target remains intact following the initial strike, the terrorist can attach a new missile tube to the grip stock launcher and fire again.

WATERBORN ATTACKS

Waterborne defenses of nuclear plants adjacent to navigable waterways must be significantly enhanced. Facilities must either be engineered to withstand damage from a waterborne attack or suited with physical barriers that prevent entry to the plant and/or critical cooling intake equipment.

Continual cooling is an essential component of nuclear plant safety. A meltdown can be triggered even at a scrammed reactor if cooling is obstructed. Water intake is also essential to the proper function of spent fuel pools. Yet at certain nuclear plants, cooling systems may be highly vulnerable. At both Indian Point and Millstone Power Station, in particular, water intake pipes have been identified by engineering experts as exposed and susceptible to waterborne sabotage.

One or more boats laden with high energy explosives could severely compromise cooling water intakes easily and quickly. Indian Point, for instance, is located on the banks of the Hudson River in an area heavily trafficked by commercial and recreational vessels. The 900 foot "Exclusion Zone" -marked only by buoys- could be traversed by speed boats in 30 - 40 seconds, well before any Coast Guard or other patrol boat could react. Patrol boats could also be readily taken out by suicide bomber boats crashing into them (in the manner a small explosives laden boat targeted the destroyer the USS Cole in 2000) or by weaponry like shoulder-fired missiles or rocket propelled grenades.

AERIAL ASSAULT

According to a terrorist "threat matrix" issued by the National Research Council and the National Academies of Sciences and Engineering following the September 2001 attack, "Nuclear power plants may present a tempting high-visibility target for terrorist attack, and the potential for a September 11-type surprise attack in the near term using U.S. assets such as airplanes appears to be high."

In March 2005, a joint FBI and Department of Homeland Security assessment stated that commercial airlines are "likely to remain a target and a platform for terrorists" and that "the largely unregulated" area of general aviation (which includes corporate jets, private airplanes, cargo planes, and chartered flights) remains especially vulnerable. The assessment further noted that Al Qaeda has "considered the use of helicopters as an alternative to recruiting operatives for fixed-wing operations," adding that the maneuverability and "non-threatening appearance" of helicopters, even when flying at low altitudes, makes them "attractive targets for use during suicide attacks or as a medium for the spraying of toxins on targets below."

The vulnerability of nuclear power plants to malevolent airborne attack is detailed extensively in the Petition filed by the National Whistleblower Center and Randy Robarge in 2002 pursuant to 10 CFR Sec. 2.206. A number of studies of the issue are also reviewed in Appendix A to these Comments. The particular vulnerability of nuclear spent fuel pools to this kind of attack is detailed in the January 2003 report of Dr. Gordon Thompson, director of the Institute for Resource and Security Studies entitled "Robust Storage of Spent Nuclear Fuel: A Neglected Issue of Homeland Security" and in the findings of a multi-institution team study led by Frank N. Von Hippel, a physicist and co-director of the Program on Science and Global Security at Princeton University and published in the spring 2003 edition of the Princeton journal *Science and Global Security* under the title "Reducing the Hazards from Stored Spent Power-Reactor Fuel in the United States." It is worthy of note that, even post-9/11, general aviation aircraft have circled or flown closely over commercial nuclear facilities without military interception.

The NRC's sole present strategy for averting a kamikaze attack upon a nuclear power plant is reliance upon aviation security upgrades implemented by the Transportation Security Administration and the Federal Aviation Administration and faith that U.S. intelligence will provide ample warning.

It is this kind of governmental agency pass-the-buck mindset that brought the nation Katrina.

The NRC's conjecture also betrays a reality disconnect reminiscent of the federal response to Katrina. Since 2001 there have been numerous breaches of airport security throughout the nation. Notably, in late 2005, there were three serious security breaches at Newark International Airport, one of the points of departure used by the September 11 hijackers. The most serious occurred on November 12, 2005, when a man driving a large S.U.V. barreled through the armed security checkpoint and drove in a secured area for 45 minutes before being found by NY/NJ Port Authority officers. Just this year, gaping holes in airport security were exposed when workers with access to secure areas were able to carry firearms in their carry-on bags onto a commercial jet departing from Florida.

The PRSR must furthermore be upgraded to include high-speed attack by a jumbo jet of the maximum size anticipated to be in commercial use (such as the expanded version of the Boeing 747 and the Airbus A380) as well as unexpected attack by general aviation aircraft and helicopters. The PRSR must contemplate all such aircraft to be fully loaded, fueled and armed with explosives.

It is essential that the PRSR address not only the direct effect of impact, but the full potential aftereffects of (A) induced vibrations; (B) dislodged debris falling onto sensitive equipment; (C) a fuel fire; and (D) the combustion of aerosolized fuel (especially in combination with pre-existing on-site gases such as hydrogen).

The PRSR must further take into consideration the cascading consequences of aerial assault on the full spectrum of plant installations. Inarguably, there is a wide range of on-site structures, not within hardened containment, that are critical to the safe operation of a nuclear plant. Spent fuel pools are of particular concern because the disposition of water could uncover the fuel. If plant workers are unable to effectuate replacement of the water (either because of fire or because they are otherwise incapacitated), experts warn, an exothermic reaction could cause the zirconium clad spent fuel rods to ignite a nuclear waste conflagration that would very likely spew the entire radioactive contents of the spent fuel pool into the atmosphere.

Without question, hardening a nuclear power plant against aerial threat will necessitate significant upgrades in plant fortification. However even relatively modest measures such as the installation of Beamhenge and the placement of all sufficiently cooled spent fuel into Hardened On-Site Storage Systems (known as H.O.S.S.) would add measurable protection.

STRATEGIC USES OF RIGS, TRUCKS AND S.U.V.'S

In June 1991, the NRC denied the truck bomb petition of the Committee to Bridge the Gap and the Nuclear Information Resource Service, on the grounds that it was not realistic to believe a truck bomb would be employed in the U.S. Two years later, on February 26, 1993, terrorists drove a rented van packed with explosives into the underground garage of the World Trade Center, lighted a fuse and fled. Just a couple of weeks before that, a mentally unstable individual crashed his station wagon through the gates of the protected area of the Three Mile Island nuclear power station and evaded security for several hours before finally wrecking his vehicle by crashing into the turbine building. Thereafter, the NRC reconsidered its earlier assessment and has, on a number of occasions, upgraded reactor security standard to include some protections against land vehicles. Such upgrades, however, are insufficient in a post-9/11 world.

Large Sport Utility Vehicles and pickup trucks on the road today can weigh over 8 tons, loaded, and -as do commercial vans- have considerably carrying capacity. Such vehicles could be used strategically in a number of ways.

The first is as a mobile short range projectile bomb. A large, heavy vehicle packed with high explosives, even if not successful in penetrating concrete barriers, could result in the death or incapacitation of large

numbers of plant workers, including security, personnel. Such casualties would be particularly likely to materialize if the vehicle bomb followed a previous diversionary event intended to draw security personnel to the plant perimeter.

The second is as a transport vehicle for one team of attackers who are themselves armed or who wear explosive belts and could then themselves penetrate other areas of the facility. A terrorist wearing an explosive body belt can, in effect, be a precision guided weapon.

The third and fourth scenarios are variations of the first two, with chemical agents substituted for or combined with explosives. (Indeed, insurgents in Iraq are increasingly combining explosives with chlorine gas and other chemical payloads in truck bomb detonations.) One or two such vehicles packed with the right toxins, could be expected to kill or disable a substantial number of workers, again, especially if the release followed a prior event which drew security personnel to the area, or simply to areas outside facility enclosures. Certain toxins can be lethal to anyone within miles. Using such agents, attackers wearing protective gear could then gain access to other areas of the facility.

A fifth tactical use of vehicles would not even occur on site. Vehicles carrying explosives and/or chemical agents could be set off at critical regional transportation arteries such as major bridges, tunnels and highways. Notably, such incidents could be staged in a way that would not even alert authorities to the onset of terrorist activity. In the New York metropolitan region in which Indian Point is sited, for example, a series of major accidents occurring at or about the same time would not be an unusual occurrence. In fact, on July 25, 2003, the very day the Federal Emergency Management Agency declared that the Indian Point emergency plan provided "adequate" assurance of protection to the public, the entire New York metropolitan region was brought to a virtual traffic standstill after a tractor-trailer hit a beam on the George Washington Bridge and burst into flames, several minor accidents and a car fire took place on Interstate 95, and a truck got jammed under an overpass of the Hutchinson River Parkway. In 2006, a tanker truck carrying 8000 gallons of gasoline overturned on one of New York City's busiest highways, igniting a blaze that burned for hours and weakening the steel beams of an above bridge. Earlier this month a liquid propane explosion closed a 23 mile stretch of the New York State Thruway for hours, while firefighters had to stand by and watch the fire burn out because it was too hot to approach.

The staging of a couple of incidents like those just noted, combined with an "accident" involving a tanker carrying hazardous gasses or liquids like liquefied ammonia, propane, chlorine, or vinyl chloride, prior to an assault would almost assuredly forestall the provision of outside assistance to a nuclear facility under attack.

PLANTS MUST BE ABLE TO MOUNT A FULL DEFENSE WITHOUT RELIANCE ON OUTSIDE ASSISTANCE

Whether or not an attack employs strategies designed to obstruct regional transportation routes, numerous studies and the actual events of 9/11, Katrina, and Rita (as well as relatively minor events such as the January 18, 2006 wind storm in NY) demonstrate beyond cavil that first responder forces and the National Guard do not have the resources, manpower, equipment or communications capabilities to swiftly and adequately respond to a major assault on a nuclear facility. Just this very month, a report of the Commission on the National Guard and Reserves detailed the ongoing problem of inadequate human, equipment, communications and financial resources plaguing the National Guard. This report calls into question the ability of the government to bring all necessary assets to bear in the immediate aftermath of a major domestic incident.

In some regions - most notably the New York Metropolitan region, in which Indian Point is sited - roadway logistics and regular congestion alone would likely prevent assisting forces from reaching a nuclear plant under attack in time. It bears mention that SWAT team assembly takes approximately 2 hours, whereas an assault could be over in a matter of minutes.

It is accordingly crucial that the NRC cedes the faulty assumption that plant personnel need only fend off attackers until law enforcement or military aid arrives. The fact that most regional first responders have little detailed knowledge of either the operational or internal layout of nuclear facilities further testifies to the folly of reliance upon the "cavalry".

ELEVATED VULNERABILITY TO INFILTRATION DURING EVENT

During a crisis event at a nuclear plant there also exists an elevated threat of infiltration by terrorists posing as first responders or National Guard. And in fact the imposter tactic has been used by terrorists in recent years with substantial success.

Terrorists disguised as firefighters could take particularly strong advantage of this stratagem. Outside firefighters often respond to fires at nuclear power plants and many attack scenarios would be expected to involve fire. Firefighters would presumptively be seen as benign by plant personnel and would have a legitimate reason to move throughout a facility and "check" components such as electrical wiring. Moreover, bulky firefighter uniforms and equipment can hold and hide a host of articles that could be used for destructive purposes.

DEFENSE AGAINST A SIZABLE MULTI-TEAM, MULTI-DIRECTIONAL FORCE

In January 1991, the Nuclear Information Resource Service and the Committee to Bridge the Gap filed a joint Petition with the NRC requesting, *inter alia,* that the DBT be upgraded to 20 external attackers. The NRC rejected the petition in June 1991, asserting that an attack involving more than 3 assailants was unrealistic.

September 11 was a demonstration of the profound limitations of governmental foresight.

The September 11 plot involved 20 attackers (although only 19 were ultimately able to participate). The tragic 2004 siege at a school in Belsan, Russia involved more than 30 armed terrorists. It should be beyond question at this point that a terrorist attack could involve scores of attackers.

Accordingly, the PRSR must assume at least two dozen attackers. Lessons learned from 9/11 and the many multiple coordinated terrorist actions that have transpired in Europe, Asia and the Middle East since then, also mandate the premise that attackers will act in several teams and that some of those teams may be sizable.

Any carefully planned attack on a nuclear facility by knowledgeable individuals, would also involve several different *modus operandi.* The PRSR should therefore take into account the consequences of near-simultaneous damage to different plant installations, systems and personnel (e.g., the effect of a small explosive-laden plane diving into the roof of a spent fuel pool coupled with the waterborne sabotage of the spent fuel pool intake system).

A COORDINATED ATTACK ON MULTIPLE ON AND OFF-SITE TARGETS

A related point is that, following 9/11, the NRC can no longer ignore the very real possibility that an attack on a nuclear power plant would occur commensurate with an attack on other regional infrastructure such as chemical plants and bridges. A coordinated attack designed to effectively eradicate a region would very likely preliminarily target communication, electrical power and/or transportation infrastructures. This would ensure that (A) the targeted region is reduced to mass confusion, (B) local and federal officials and responders would be overwhelmed, and (C) law enforcement and other first responders would be impeded from gaining access to the nuclear plant site.

Certain areas of the U.S. offer a plethora of target opportunities and thus are particularly vulnerable to multiple target scenarios. Prime among them is the greater New York Metropolitan area (already in the terrorists' crosshairs) which contains numerous national landmarks, corporate headquarters, reservoirs, bridges, airports, transportation arteries and hazardous chemical plants, all in near vicinity to Indian Point, a mere 24 miles north of New York City.

A CREDIBLE NUCLEAR PLANT SECURITY FORCE TESTING PROGRAM

The deficiencies, failures, and chicanery that have long plagued the various manifestations of nuclear

power industry security drills and force-on-force (FOF) testing have been exhaustively documented in recent years. Noteworthy investigations in this regard have been conducted by the Project on Government Oversight (augmented by testimony provided in 2002 Senate Environment and Public Works Committee hearings) and the United States General Accounting Office (which reported its findings in a September 2003 report entitled "Oversight of Security at Commercial Nuclear Power Plants Needs to Be Strengthened") as well as by the press. Problems with the FOF program are also addressed in the July 2004 Petition for Rulemaking to amend 10 CFR Part 73 to upgrade the DBT filed by the Committee to Bridge the Gap and the Comments on the DBT filed in 2006 by the Union of Concerned Scientists. CIECP fully endorses the recommendations made in previous filings by the Committee to Bridge the Gap and the Union of Concerned Scientists.

CIECP urges the NRC in the strongest possible terms to upgrade drills and testing protocols to remedy the flaws that are a matter of public record and to take into account the realities noted herein. FOF tests must be sufficiently challenging to provide high confidence in the defensive capabilities of the security forces at the nation's 103 nuclear power plants. One clear failing of the FOF program to date has been the giving of excessive warning regarding upcoming tests. While some notice is necessary, one week should suffice. In addition, staff assignments should be frozen on the day of notice. This would eliminate the all too common practice of substituting a plant's most fit and accomplished security personnel in place of underachievers.

It is also critical that drills and the FOF program be revamped to eliminate manifest conflicts of interest. Examples of blatant conflicts of interest include: (1) The NRC allowing the nuclear industry's lobbying arm, the Nuclear Energy Institute (NEI) to award a FOF contract; and (2) The NEI, with NRC approval, then selecting Wackenhut, a corporation which contracts security guards to nuclear power plants in the U.S., to also be the contractor that supplies the mock adversary teams for the FOF tests.

Such problems have reduced the value of testing to the point where the FOF program lacks public confidence. The program must be redesigned and monitored by an independent entity such as the very capable U.S. military.

HIGH TARGET APPEAL REACTORS

Prior terrorist attacks and plots against the U.S. have focused on major cities. It is a matter of fundamental logic that plants sited in highly populated metropolitan areas, particularly those with high symbolic value, face the greatest risk of being selected as a target.

It is thus imperative that the PRSR be modified to mandate a customized approach to high target nuclear facilities.

SITE-SPECIFIC SAFETY-RELATED VULNERABILITIES

It is highly unrealistic to exclude from the PRSR calculus the reality of aging structures, deteriorated conditions and compromised systems that exist at various nuclear power plants in the U.S. A facility-customized approach must be taken which adds problems which are known or reasonably suspected and which could have a significant effect upon the ability of plant operators to maintain control during a major incident into the security equation.

Prime among factors which may be site-specific are:

o Corrosion and Embrittlement: For example, a risk of corrosion of the steel liner of the reactor containment at the Oyster Creek Nuclear Generating Station (Oyster Creek) was recently identified. A qualified corrosion expert has warned that the risk may be high enough to cause buckling and collapse. Manifestly, corrosion or embrittlement-weakened structures and components are more vulnerable to the effects of heat and combustion.

o Vulnerability to Fire: Fire detection and suppression equipment and fire barriers are crucial to reactor safety. Over 20 years ago a worker at the Brown's Ferry Unit 1 reactor accidentally started a fire which destroyed emergency cooling systems and severely compromised the plant's ability to monitor its

condition. In response, the NRC increased fire safety standards. In recent years, the NRC has effectively relaxed those standards. This is exceedingly unwise. During the chaos and threat level that would surely exist during a terrorist attack, human beings cannot be presumed to be able to take the actions necessary to protect critical systems from fire. The systems themselves must have integral safeguards. Yet plants such as Arkansas Nuclear One, Catawba, Ginna, H.B. Robinson, Indian Point, James A. Fitzpatrick, McGuire, Shearon Harris, Vermont Yankee and Waterford have been identified as having fire barrier wrap systems that failed fire tests. Fireproofing problems such as these jeopardize safe shutdown and must be recognized as a degradation of defense-in-depth protection. In addition, any plant fire hazard analyses must assume damage to multiple rooms and multiple structures, a circumstance that could easily result from an aircraft impact.

o Integrity of Structures that Support Mobility: While the focus of NRC regulatory review is on structures and equipment directly related to safe operational function, the conditions that may prevail during an assault would likely require plant personnel to be able to move rapidly throughout the facility. The evaluation of the reliability of structural features such as stairways (which might buckle or melt during a fire) is accordingly critical.

o Electrical System Problems: In 2003, a cable failure knocked out power to approximately half the safety systems at Oyster Creek, including security cameras, alarms, sensors, pumps and valves. In February 2003, all 4 of the backup generators at Fermi became simultaneously inoperable. In December 2001, Indian Point reactor 2 lost power due to a malfunction of the turbine, then lost back-up power to the reactor coolant system because of a second electrical failure. During the August 2003 blackout that struck the Northeast, following the loss of off-site power, two of Indian Point's emergency backup generators (both of which had been previously flagged as having problems) failed to operate. In view of the severe consequences failures such as these could have were they to occur during a major incident, known plant electrical system vulnerabilities must be taken into consideration.

o Cooling System Problems: Cooling system problems and design deficiencies have plagued a number of plants in recent years. In some cases the NRC has allowed plants to operate for long periods with compromised emergency cooling systems. For example, the Salem nuclear power station had experienced two years of repeated malfunctions of its high-pressure coolant-injection system prior to the time, in October 2003, when operators unsuccessfully tried to use it to stabilize water levels following a steam pipe burst. And the NRC has allowed reactors with emergency sump pumps flagged as likely to become clogged and inoperative to remain in operation for many years without repair. The Los Alamos National Laboratory, for instance, concluded that the sump pumps at Indian Point reactors 2 and 3 could become clogged in as little as 23 minutes and 14 minutes, respectively. While, upgrades are being made, the failure of the NRC to mandate immediate correction of cooling system vulnerabilities calls its oversight capabilities seriously into question. Indeed the functional declination of critical systems must be deemed a constituent element of site-specific PRSR analyses.

ELIMINATE COMMERCIAL CONSIDERATIONS FROM THE PRSR CALCULUS

The commercial interests of the nuclear industry are of valid concern to nuclear utilities and the NEI; they should not be of concern to the NRC. There is no justification for jeopardizing national security and the health and safety of the public - even to the smallest degree - to safeguard corporate profits.

The NRC has stated that its promulgated security standards are based upon the analysis of the largest threat against which a "**private security force could reasonably be expected to defend**" [*emphasis added*] 70 FR 67385.

Both the NRC and the industry have acknowledged that, in their estimation, a private guard force should not be reasonably expected to defend against a 9/11-type attack involving aircraft. Such an attack, apparently, is deemed to fall under the loophole of 10 CFR Sec. 50.13, which exempts reactor operators from defending against "an enemy of the United States, a foreign government or other person". The perimeter of this "enemy of the United States provision has never been defined, so there is no way to know how far it extends. However, it is abundantly clear from the public record that the NRC has drawn the line at point where the profit margins of nuclear power operators might be significantly affected. Unfortunately, the terrorists are constrained by no such boundary.

Congress has charged the NRC with the obligation to protect the public health and safety. This must not be viewed simply as a guideline; it must be viewed as an uncompromised mandate.

If the NRC does not believe its licensees can afford the security upgrades necessary to protect the nation's nuclear reactors against the full potential threat, it must act with forthrightness and publicly demand that the Department of Homeland Security or the U.S. military assume responsibility for domestic nuclear power plant security.

CONCLUSION

The 9/11 Commission observed: "Across the government, there were failures of imagination, policy, capabilities...The most important failure was one of imagination. We do not believe leaders understood the gravity of the threat."

As a public interest group we ask: What needs to happen before the gravity of the threat is not only understood, but acted upon?

Respectfully submitted,

COUNCIL ON INTELLIGENT ENERGY
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APPENDIX A

Since September 11, 2001, there has been much speculation about the vulnerability of nuclear power plants to aerial attack. Certainty, however, is in short supply.

What is known is that none of the nuclear reactors presently operational in the United States were built to withstand the crash of a jumbo jet, much less the crash of super jumbo such as the A380 which will take to the air weighing 1.2 million pounds, has a wingspan almost as long as a football field, is 8 stories tall, and is 3 times as large as the 767s that brought down the Twin Towers.

Nevertheless studies that have addressed the prospect of planes hitting nuclear plants include the following:

1974: To date the only published peer reviewed study on the vulnerability of U.S. nuclear power plants was conducted by General Electric, the leading builder of nuclear plants, and published in the industry journal *Nuclear Safety*. GE looked at accidents -not terror attacks - and concluded that were a "heavy" airliner to hit a reactor building in the right place, it would almost certainly rip it apart. Such a hit would also most likely damage the reactor core and both the cooling and emergency cooling systems. [NOTE: The GE study defined a "heavy" plane as one weighing more than 6 tons. The Boeing 757 which gouged a 100 foot gash through the reinforced concrete of the Pentagon weighed between 80 and 100 tons. A fully loaded 767 weighs over 200 tons. The Airbus 380, expected to be launched into commercial use later this year, takes to the air weighing 1.2 million pounds, hundreds of thousands of pounds heavier

than the Boeing 747, the current jumbo of the sky.]

1982: A technical report (previously publicly available) of a study conducted by the U.S. Army Corps of Engineers at the NRC's behest focused on plane crash analyses at the Argonne National Laboratory. The Corps concluded that planes traveling at a speed of over 466 mph would crash through the average reactor containment structure noting "account has been taken of the internal concrete wall which acts as a missile barrier...It would appear, however, that this is too optimistic since vaporized fuel, hot gaseous reaction products, and to a certain extent portions of liquid fuel streams will flow around such obstructions and overwhelm internal defenses...." [NOTE: An FBI analysis estimated that American Airlines Flight 11, which hit the north tower of the World Trade Center, was traveling at a speed of 494 mph, and that United Airlines Flight 175, which hit the south tower, was traveling at 586 mph, a speed far exceeding its design limit for the altitude.]

2000: A NRC study published less than a year before September 11 calculated that 1 out 2 commercial airplanes flying in the year 2000 were large enough to penetrate even a 5 foot thick reinforced concrete wall 45% of the time. Specifically, the study states, "aircraft damage can affect the structural integrity of the spent fuel pool or the availability of nearby support systems, such as power supplies, heat exchangers, or water makeup sources and may also affect recovery actions...It is estimated that half the commercial aircraft now flying are large enough to penetrate the 5 foot thick reinforced concrete walls." [NOTE: The thickness of the top of certain reactor domes is 3 and-a-half feet.]

2002: The German Reactor Safety Organization (GRS) a scientific-technical research group that works primarily for nuclear regulators in Germany conducted an extremely detailed study that determined that terrorists can, with a strategically targeted airplane crash, initiate a nuclear accident. (A secret Ministry document that summarized the report was leaked to the German and Austrian press and subsequently translated into English.) The GRS study used dynamic computation modeling that looked at the potential consequences of a wide range of impact possibilities on different plant equipment and installations. Different types of airplanes, velocities, angles of impact, weight loads and fuel effects were considered, as were various sequences of events. Aside from the basic finding of vulnerability, the GRS study is significant for recognizing the limitations of even its highly complex analyses. Key unknowns include the impacts of fire loads on many kind of materials and equipment as well as the behaviors of various combustive materials under the conditions of a plane crash.

2004: In 2004 the U.K. Parliamentary Office of Science and Technology (OST) issued a secret report on the risks of terrorist attacks on nuclear facilities to the U.K. House of Commons Defense Committee. The OST report was leaked to the magazine *New Scientist*, which reported the OST conclusion that a large plane crash into a nuclear reactor could release as much radiation as the1986 accident at Chernobyl, while a crash into the nuclear waste tanks at the U.K.'s Sellafield facility could cause several million fatalities.

From these studies it is clear that there exists a reasonable basis for concern regarding malevolent deployment of aircraft against nuclear power facilities.

It should also be evident that all studies on this topic are, in substance, educated conjecture. The current state of computer modeling is not up to analyzing the full range of physical and chemical interactions that could occur under the incalculable range of different kinds of aircraft, approaching at different angles, at different speeds, hitting different structures, which all have facility-unique room and equipment layouts, and different substance, chemical, and ventilation-related conditions.

A lesson in the unpredictable consequences of airplane crashes was brought home on September 11 (when even the 47 story tall 7 World Trade Center that was not struck collapsed for reasons engineers have yet to fully determine). A lesson in the limitations of advanced computer modeling can also be learned from the Columbia space shuttle disaster.

[~DBT and PRSR]

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Nuclear Power Plants: Vulnerability to Terrorist Attack

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Summary

Protection of nuclear power plants from land-based assaults, deliberate aircraft crashes, and other terrorist acts has been a heightened national priority since the attacks of September 11, 2001. The Nuclear Regulatory Commission (NRC) has strengthened its regulations on nuclear reactor security, but critics contend that implementation by the industry has been too slow and that further measures are needed. Several provisions to increase nuclear reactor security are included in the Energy Policy Act of 2005, signed August 8, 2005. The new law requires NRC to conduct "force on force" security exercises at nuclear power plants at least once every three years and to revise the "design-basis threat" that nuclear plant security forces must be able to meet, among other measures. This report will be updated as events warrant.

Nuclear power plants have long been recognized as potential targets of terrorist attacks, and critics have long questioned the adequacy of the measures required of nuclear plant operators to defend against such attacks. Following the September 11, 2001, attacks on the Pentagon and the World Trade Center, the Nuclear Regulatory Commission (NRC) began a "top-to-bottom" review of its security requirements. On February 25, 2002, the agency issued "interim compensatory security measures" to deal with the "generalized high-level threat environment" that continued to exist, and on January 7, 2003, it issued regulatory orders that tightened nuclear plant access. On April 29, 2003, NRC issued three orders to restrict security officer work hours, establish new security force training and qualification requirements, and increase the "design basis threat" that nuclear security forces must be able to defeat.

Security Regulations

Under the regulations in place prior to the September 11 attacks, all commercial nuclear power plants licensed by NRC must be protected by a series of physical barriers and a trained security force. The plant sites are divided into three zones: an "owner-controlled" buffer region, a "protected area," and a "vital area." Access to the protected area is restricted to a portion of plant employees and monitored visitors, with stringent

access barriers. The vital area is further restricted, with additional barriers and access requirements. The security force must comply with NRC requirements on pre-hiring investigations and training.[1]

Design Basis Threat. The severity of attacks to be prepared for are specified in the form of a "design basis threat" (DBT). One of NRC's April 2003 regulatory orders changed the DBT to "represent the largest reasonable threat against which a regulated private guard force should be expected to defend under existing law," according to the NRC announcement. The details of the revised DBT, which took effect October 29, 2004, were not released to the public.

NRC requires each nuclear power plant to conduct periodic security exercises to test its ability to defend against the design basis threat. In these "force on force" exercises, monitored by NRC, an adversary force from outside the plant attempts to penetrate the plant's vital area and damage or destroy key safety components. Participants in the tightly controlled exercises carry weapons modified to fire only blanks and laser bursts to simulate bullets, and they wear laser sensors to indicate hits. Other weapons and explosives, as well as destruction or breaching of physical security barriers, may also be simulated. While one squad of the plant's guard force is participating in a force-on-force exercise, another squad is also on duty to maintain normal plant security. Plant defenders know that a mock attack will take place sometime during a specific period of several hours, but they do not know what the attack scenario will be. Multiple attack scenarios are conducted over several days of exercises.

Full implementation of the force-on-force program coincided with the effective date of the new DBT in late 2004. Standard procedures and other requirements have been developed for using the force-on-force exercises to evaluate plant security and as a basis for taking regulatory enforcement action. Many tradeoffs are necessary to make the exercises as realistic and consistent as possible without endangering participants or regular plant operations and security. Each plant is required to conduct NRC-monitored force-on-force exercises once every three years.

NRC required the nuclear industry to develop and train a "composite adversary force" comprising security officers from many plants to simulate terrorist attacks in the force-on-force exercises. However, in September 2004 testimony, the Government Accountability Office (GAO) criticized the industry's selection of a security company that guards about half of U.S. nuclear plants, Wackenhut, to also provide the adversary force. In addition to raising "questions about the force's independence," GAO noted that Wackenhut had been accused of cheating on previous force-on-force exercises by the Department of Energy.[2]

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[1] General NRC requirements for nuclear power plant security can be found at 10 CFR 73.55.

[2] Government Accountability Office. *Nuclear Regulatory Commission: Preliminary Observations on Efforts to Improve Security at Nuclear Power Plants.* Statement of Jim Wells, Director, Natural Resources and Environment, Government Accountability Office, to the Subcommittee on National Security, Emerging Threats, and International Relations, House Committee on Government Reform. September 14, 2004. p. 14.

Congress imposed statutory requirements for the DBT and force-on-force exercises in the Energy Policy Act of 2005, signed August 8, 2005. The act requires that each nuclear plant undergo force-on-force exercises at least once every three years (NRC's current policy), that the exercises simulate the threats in the DBT, and that NRC "mitigate any potential conflict of interest that could influence the results of a force-on-force exercise, as the Commission determines to be necessary and appropriate."

The new law requires NRC to revise the DBT within 18 months, after considering a wide variety of potential modes of attack (physical, chemical, biological, etc.), the potential for large attacks by multiple teams, potential assistance by several employees inside a facility, the effects of large explosives and other modern weaponry, and other specific factors.

Emergency Response. After the 1979 accident at the Three Mile Island nuclear plant near Harrisburg, PA, Congress required that all nuclear power plants be covered by emergency plans. NRC requires that within an approximately 10-mile Emergency Planning Zone (EPZ) around each plant the operator must maintain warning sirens and regularly conduct evacuation exercises monitored by NRC and the Federal Emergency Management Agency (FEMA). In light of the increased possibility of terrorist attacks that, if successful, could result in release of radioactive material, critics have renewed calls for expanding the EPZ to include larger population centers.

Another controversial issue regarding emergency response to a radioactive release from a nuclear power plant is the distribution of iodine pills. A significant component of an accidental or terrorist release from a nuclear reactor would be a radioactive form of iodine, which tends to concentrate in the thyroid gland of persons exposed to it. Taking a pill containing non-radioactive iodine before exposure would prevent absorption of the radioactive iodine. Emergency plans in many states include distribution of iodine pills to the population within the EPZ, which would protect from exposure to radioactive iodine, although giving no protection against other radioactive elements in the release. NRC in 2002 began providing iodine pills to states requesting them for populations within the 10-mile EPZ.

Nuclear Plant Vulnerability

Operating nuclear reactors contain large amounts of radioactive fission products which, if dispersed, could pose a direct radiation hazard, contaminate soil and vegetation, and be ingested by humans and animals. Human exposure at high enough levels can cause both short-term illness and death, and longer-term deaths by cancer and other diseases.

To prevent dispersal of radioactive material, nuclear fuel and its fission products are encased in metal cladding within a steel reactor vessel, which is inside a concrete "containment" structure. Heat from the radioactive decay of fission products could melt the fuel-rod cladding even if the reactor were shut down. A major concern in operating a nuclear power plant, in addition to controlling the nuclear reaction, is assuring that the core does not lose its coolant and "melt down" from the heat produced by the radioactive fission products within the fuel rods. Therefore, even if plant operators shut down the reactor as they are supposed to during a terrorist attack, the threat of a radioactive release would not be eliminated.

Commercial reactor containment structures — made of steel-reinforced concrete several feet thick — are designed to prevent dispersal of most of a reactor's radioactive material in the event of a loss of coolant and meltdown. Without a breach in the containment, and without some source of dispersal energy such as a chemical explosion or fire, the radioactive fission products that escaped from the melting fuel cladding mostly would remain where they were. The two major meltdown accidents that have taken place in power reactors, at Three Mile Island in 1979 and at Chernobyl in the Soviet Union in 1986, illustrate this phenomenon. Both resulted from a combination of operator error and design flaws. At Three Mile Island, loss of coolant caused the fuel to melt, but there was no fire or explosion, and the containment prevented the escape of substantial amounts of radioactivity. At Chernobyl, which had no containment, a hydrogen explosion and a fierce graphite fire caused a significant part of the radioactive core to be blown into the atmosphere, where it contaminated large areas of the surrounding countryside and was detected in smaller amounts literally around the world.

Vulnerability from Air Attack. Nuclear power plants were designed to withstand hurricanes, earthquakes, and other extreme events, but attacks by large airliners loaded with fuel, such as those that crashed into the World Trade Center and Pentagon, were not contemplated when design requirements were determined. A taped interview shown September 10, 2002, on Arab TV station al-Jazeera, which contains a statement that Al Qaeda initially planned to include a nuclear plant in its 2001 attack sites, intensified concern about aircraft crashes.

In light of the possibility that an air attack might penetrate the containment building of a nuclear plant, some interest groups have suggested that such an event could be followed by a meltdown and widespread radiation exposure. Nuclear industry spokespersons have countered by pointing out that relatively small, low-lying nuclear power plants are difficult targets for attack, and have argued that penetration of the containment is unlikely, and that even if such penetration occurred it probably would not reach the reactor vessel. They suggest that a sustained fire, such as that which melted the structures in the World Trade Center buildings, would be impossible unless an attacking plane penetrated the containment completely, including its fuel-bearing wings.

Recently completed NRC studies "confirm that the likelihood of both damaging the reactor core and releasing radioactivity that could affect public health and safety is low," according to NRC Chairman Nils Diaz. However, NRC is considering studies of additional measures to mitigate the effects of an aircraft crash.[3]

Spent Fuel Storage. Radioactive "spent" nuclear fuel — which is removed from the reactor core after it can no longer efficiently sustain a nuclear chain reaction — is stored in pools of water in the reactor building or in dry casks elsewhere on the plant grounds. Because both types of storage are located outside the reactor containment structure, particular concern has been raised about the vulnerability of spent fuel to attack by aircraft or other means. Spent fuel pools and dry cask storage facilities are subject to NRC security requirements.

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[3] Letter from NRC Chairman Nils J. Diaz to Secretary of Homeland Security Tom Ridge, September 8, 2004.

The primary concern is whether terrorists could breach the thick concrete walls of a spent fuel pool and drain the cooling water, which could cause the spent fuel's zirconium cladding to overheat and catch fire. A report released in April 2005 by the National Academy of Sciences (NAS) found that "successful terrorist attacks on spent fuel pools, though difficult, are possible," and that "if an attack leads to a propagating zirconium cladding fire, it could result in the release of large amounts of radioactive material." NAS recommended that the hottest spent fuel be interspersed with cooler spent fuel to reduce the likelihood of fire, and that water-spray systems be installed to cool spent fuel if pool water were lost. The report also called for NRC to conduct more analysis of the issue and consider earlier movement of spent fuel from pools into dry storage.[4]

Both the House- and Senate-passed versions of the FY2006 Energy and Water Development appropriations bill (H.R. 2419, H.Rept. 109-86, S.Rept. 109-84) would provide $21 million for NRC to carry out the NAS recommendations. The House Appropriations Committee was particularly critical of NRC's actions on spent fuel storage security: "The Committee expects the NRC to redouble its efforts to address the NAS-identified deficiencies, and to direct, not request, industry to take prompt corrective actions."

Regulatory and Legislative Proposals

Critics of NRC's security measures have demanded both short-term regulatory changes and legislative reforms.

A fundamental concern was the nature of the DBT, which critics contended should be increased to include a number of separate, coordinated attacks. Critics also contended that nearly half of the plants tested in NRC-monitored mock attacks before 9/11 failed to repel even the small forces specified in the original DBT, a charge that industry sources vigorously denied. Critics also pointed out that licensees are required to employ only a minimum of five security personnel on duty per plant, which they argue is not enough for the job.[5] Nuclear spokespersons responded that the actual security force for the nation's 65 nuclear plant sites numbers more than 5,000, an average of about 75 per site (covering multiple shifts). Nuclear plant security forces are also supposed to be aided by local law enforcement officers if an attack occurs.

In February 2002, NRC implemented what it called "interim compensatory security measures," including requirements for increased patrols, augmented security forces and capabilities, additional security posts, installation of additional physical barriers, vehicle checks at greater stand-off distances, enhanced coordination with law enforcement and military authorities, and more restrictive site access controls for all personnel. The further

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[4] National Academy of Sciences, Board on Radioactive Waste Management, *Safety and Security of Commercial Spent Nuclear Fuel Storage, Public Report* (online version), released April 6, 2005.

[5] 10 CFR 73.55 (h)(3) states: "The total number of guards, and armed, trained personnel immediately available at the facility to fulfill these response requirements shall nominally be ten (10), unless specifically required otherwise on a case by case basis by the Commission; however, this number may not be reduced to less than five (5) guards."

orders issued April 29, 2003, expanded on the earlier measures, including revising the DBT, which critics continue to describe as inadequate. Continuing congressional concerns resulted in the new criteria in the Energy Policy Act of 2005 for further DBT revisions.

Because of the growing emphasis on security, NRC established the Office of Nuclear Security and Incident Response on April 7, 2002. The office centralizes security oversight of all NRC-regulated facilities, coordinates with law enforcement and intelligence agencies, and handles emergency planning activities. Force-on-force exercises are an example of the office's responsibilities. On June 17, 2003, NRC established the position of Deputy Executive Director for Homeland Protection and Preparedness, whose purview includes the Office of Nuclear Security and Incident Response.

Legislation. Since the 9/11 attacks, numerous legislative proposals, including some by NRC, have focused on nuclear power plant security issues. Several of those ideas, such as the revision of the design-basis threat and the force-on-force security exercises, were included in the Energy Policy Act of 2005, which also includes:

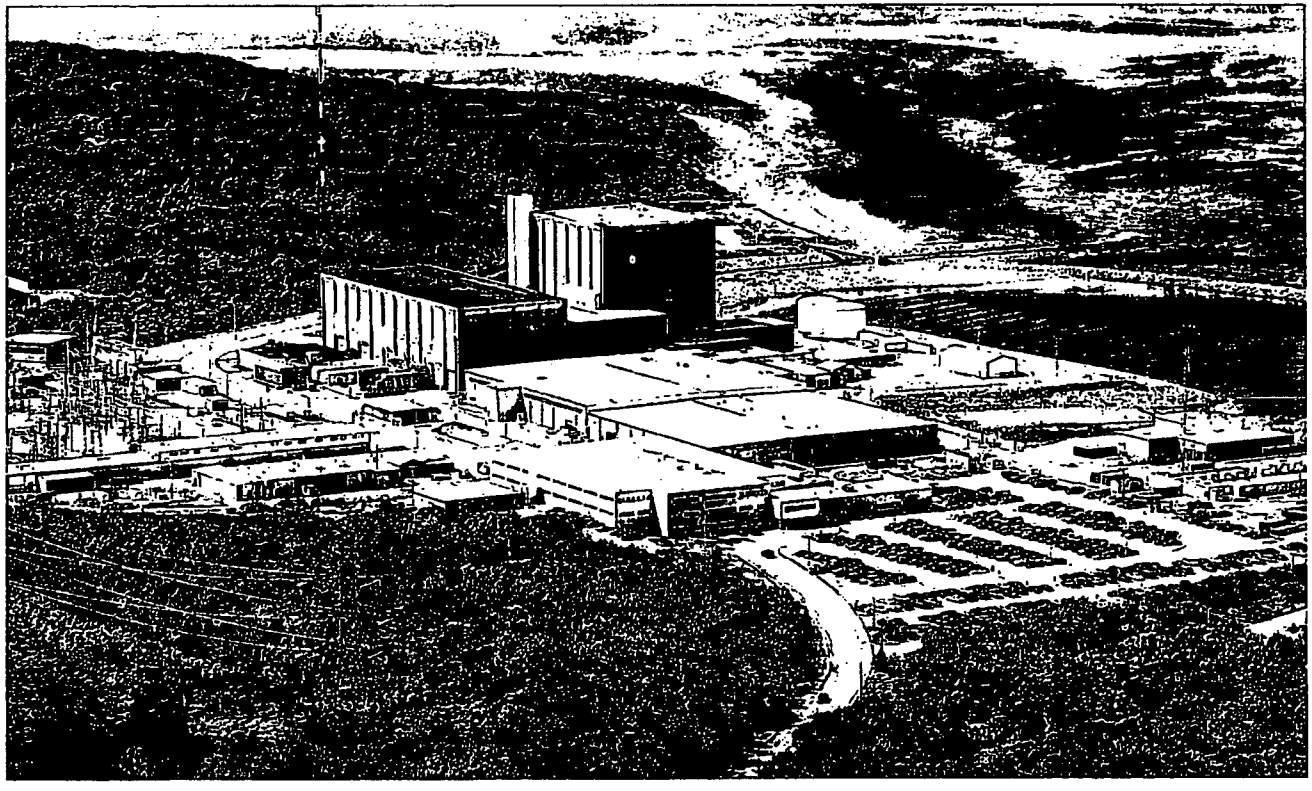
- assignment of a federal security coordinator for each NRC region;
- backup power for nuclear plant emergency warning systems;
- tracking of radiation sources;
- fingerprinting and background checks for nuclear facility workers;
- authorizing use of firearms by nuclear facility security personnel (preempting some state restrictions);
- authorizing NRC to regulate dangerous weapons at licensed facilities;
- extending penalties for sabotage to cover nuclear facilities under construction;
- requiring a manifest and personnel background checks for import and export of nuclear materials; and
- requiring NRC to consult with the Department of Homeland Security on the vulnerability to terrorist attack of locations of proposed nuclear facilities before issuing a license.

A number of legislative proposals introduced since 9/11 to increase nuclear plant security were not included in the new law, including the creation of a federal force within the NRC to replace the private guards at nuclear power plants, requiring emergency planning exercises within a 50-mile radius around each nuclear plant, and stockpiling iodine pills for populations within 200 miles of nuclear plants. Other measures proposed but not enacted include a task force to review security at U.S. nuclear power plants and a federal team to coordinate protection of air, water, and ground access to nuclear power plants.

Exhibit FP No. 16

Pilgrim Nuclear Power Station

Questions?



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NUREG-1852

Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire

Final Report

U.S. Nuclear Regulatory Commission
Office of Nuclear Regulatory Research
Washington, DC 20555-0001

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NUREG-1852

Demonstrating the Feasibility and Reliability of Operator Manual Actions in Response to Fire

Final Report

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ABSTRACT

This report provides criteria and associated technical bases for evaluating the feasibility and reliability of postfire operator manual actions implemented in nuclear power plants. The U.S. Nuclear Regulatory Commission (NRC) developed this report as a reference guide for agency staff who evaluate the acceptability of manual actions, submitted by licensees as exemption requests from the requirements of Paragraph III.G.2 of Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," to Title10, Part 50, "Domestic Licensing of Production and Utilization Facilities," of the *Code of Federal Regulations* (10 CFR Part 50), as a means of achieving and maintaining hot shutdown conditions during and after fire events. The staff may use this information in the review of *future* postfire operator manual actions to determine if the feasibility and reliability of the operator manual action were adequately evaluated.

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FOREWORD

This report provides criteria and associated technical bases for evaluating the feasibility and reliability of postfire operator manual actions implemented in nuclear power plants. The U.S. Nuclear Regulatory Commission (NRC) developed this report as a reference guide for agency staff who evaluate the acceptability of manual actions, submitted by licensees as exemption requests from the requirements of Paragraph III.G.2 of Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," to Title10, Part 50, "Domestic Licensing of Production and Utilization Facilities," of the *Code of Federal Regulations* (10 CFR Part 50), as a means of achieving and maintaining hot shutdown conditions during and after fire events. The staff may use this information in the review of *future* postfire operator manual actions to determine if the feasibility and reliability of the operator manual action were adequately evaluated. The work was performed by the NRC's Office of Nuclear Regulatory Research and Office of Nuclear Reactor Regulation, with support from Sandia National Laboratories and its contractor.

This report was developed on the basis of NRC and contractor experience in evaluating plans at nuclear power plants for human performance during fire events (e.g., inspections of plants' fire protection programs) and the review of work related to modeling human behavior in response to fires and other accident conditions in nuclear power plants. Reviewed documents include, but are not limited to, fire analyses conducted as part of individual plant examinations of external events (IPEEEs), the IPEEE summary report (NUREG-1742, "Perspectives Gained from the Individual Plant Examination of External Events [IPEEE] Program," Volumes 1 and 2, issued April 2002), fire-related operational events, the fire requantification work conducted jointly by the NRC and the Electric Power Research Institute (EPRI) (NUREG/CR-6850 [EPRI TR-1011989], "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities," issued September 2005), and the American National Standards Institute/American Nuclear Society Standard 58.8-1994, "American National Standard Time Response Design Criteria for Safety-Related Operator Actions."

The technical information provided in this report is aimed at providing assistance to agency staff when they need to evaluate that postfire operator manual actions are both feasible and reliable. In addition, the information may be useful to licensees choosing to use such an approach to demonstrate the feasibility and reliability of operator manual actions. Among the criteria provided is the importance of time-authenticated demonstrations of the manual actions (involving actual execution of the actions to the extent possible) and adequate time available to complete the actions before fire-induced consequences occur that would otherwise prevent achieving and maintaining hot shutdown.

This report focuses on *unique* aspects of the hazard involved (fire), as well as the potentially unique characteristics of subsequent manual actions during the operators' response. Hence, it does not address all the various facets of programs that could potentially impact human performance during a fire. For instance, this report does not specify in detail what constitutes

"adequate procedures"; other guidance documents already address this issue. Nonetheless, this report addresses the unique aspects of fire and associated operator manual actions to guide the NRC staff in determining whether operator manual actions, proposed by operating plants for use in achieving and maintaining hot shutdown, are feasible and can reliably be performed in response to fire.

Farouk Eltawila, Director
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CONTENTS

Figures

Tables

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ABBREVIATIONS

ANS	American Nuclear Society
ANSI	American National Standards Institute
ATHEANA	A Technique for Human Event Analysis
BWR	boiling-water reactor
CFR	*Code of Federal Regulations*
CCW	component cooling water
EOP	emergency operating procedure
EPRI	Electric Power Research Institute
ESWGR	East Switchgear Room
GL	generic letter
HRA	human reliability analysis
IN	information notice
IPEEE	individual plant examination of external events
LOCA	loss-of-coolant accident
MCR	main control room
MOV	motor-operated valve
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation (NRC)
PEO	plant equipment operator
PORV	power-operated relief valve
PWR	pressurized-water reactor
RES	Office of Nuclear Regulatory Research (NRC)
RIS	regulatory issue summary
SCBA	self-contained breathing apparatus
SPAR-H	Simplified Plant Analysis Risk—Human Reliability Analysis
SSC	structure, system, and component
WSWGR	West Switchgear Room

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GLOSSARY

Below are key terms or phrases whose definitions and associated context, for purposes of this document, are as shown.

action—An activity, typically observable, and usually involving the manipulation of equipment, that is carried out by an operator(s) to achieve a certain outcome. The required diagnosis of the need to perform the activity, the subsequent decision to perform the activity, obtaining any necessary equipment, procedures, or other aids or devices necessary to perform the activity, traveling to the location to perform the activity, implementing the activity, and checking that the activity has had its desired effect, are all implied and encompassed by the term "action."

available time (or time available)—The time period from a presentation of a cue for an action to the time of adverse consequences if the action is not taken.

diagnosis time—The time required for an operator(s) to examine and evaluate data to determine the need for, and to make the decision to implement, an action.

feasible action—An action that is analyzed and demonstrated as being able to be performed within an available time so as to avoid a defined undesirable outcome. As compared to a reliable action (see definition), an action is considered feasible if it is shown that it is possible to be performed within the available time (considering relevant uncertainties in estimating the time available); but it does not necessarily demonstrate that the action is reliable. For instance, performing an action successfully one time out of three attempts within the available time shows that the action is *feasible*, but not necessarily reliable.

implementation time—The time required by the operator(s) to successfully perform the manipulative aspects of an action (i.e., not the diagnosis aspects themselves, but typically as a result of the diagnosis aspects), including obtaining any necessary equipment, procedures, or other aids or devices; traveling to the necessary location; implementing the action; and checking that the action has had its desired effect.

*operator manual action*s (local actions, in response to a fire)—Those actions performed by operators to manipulate components and equipment from outside the main control room to achieve and maintain postfire hot shutdown, but not including "repairs." Operator manual actions comprise an integrated set of actions needed to help ensure that hot shutdown can be accomplished, given that a fire has occurred in a particular plant area.

preventive actions—Those actions that, upon entering a fire plan/procedure, the operator(s) takes (without needing further diagnosis) to mitigate the potential effects of possible spurious actuations or other fire-related failures, so as to ensure that hot shutdown can be achieved and maintained. For these actions, it is generally assumed that once the fire has been detected and located, per procedure, the control room crew will direct personnel to execute a number of actions, possibly even without the existence of other damage symptoms, to ensure the availability of equipment to achieve its function during the given fire scenario. In many cases, the only criterion for initiating these actions is the presence of the fire itself.

reactive actions—Those actions taken during a fire in response to an undesired change in plant condition. In reactive actions, the operator(s) detects the undesired change and, with the support of procedural guidance, diagnoses the correct actions to be taken. Thus, with reactive actions, the plant staff responds to indications of changing equipment conditions caused by the fire, and then takes the steps necessary to ensure that the equipment will function when needed (e.g., manually reopening a spuriously closed valve). The plant staff may not initiate the actions until the procedure indicates that, given the relevant indications, the actions must be performed.

reliable action—A feasible action that is analyzed and demonstrated as being dependably repeatable within an available time, so as to avoid a defined adverse consequence, while considering varying conditions that could affect the available time and/or the time to perform the action. As compared to an action that is only feasible (see definition), an action is considered to be reliable as well if it is shown that it can be dependably and repeatably performed within the available time, by different crews, under somewhat varying conditions that typify uncertainties in the available time and the time to perform the action, with a high success rate. All reliable actions need to be feasible, but not all feasible actions will be reliable.

1. INTRODUCTION

The primary objective of fire protection programs at U.S. nuclear plants are to minimize the effects of fires and explosions on structures, systems, and components (SSCs) important to safety. To meet this objective, fire protection programs for operating nuclear power plants are designed to provide reasonable assurance, through defense-in-depth, that (1) a fire will not prevent the performance of necessary safe shutdown functions, and (2) radioactive releases to the environment in the event of a fire will be minimized.

To provide those assurances, at least in part, many plants plan to or already rely on local operator manual actions[1] (i.e., actions outside the main control room (MCR)) to maintain hot shutdown capability. That is, operators either take preventive, local manual actions upon detecting a fire to protect critical safety equipment that might be failed or spuriously affected and rendered unavailable by the fire, or they locally and manually align critical safety equipment to perform its function when needed. Paragraph III.G.1 of Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," to Title 10, Part 50, "Domestic Licensing of Production and Utilization Facilities," of the *Code of Federal Regulations* (10 CFR Part 50) [Ref. 1] states that one train of equipment needed to maintain hot shutdown conditions shall be free of fire damage. Paragraph III.G.2 of Appendix R specifies the following three methods, any of which are acceptable, to provide reasonable assurance that at least one means of achieving and maintaining hot shutdown conditions will remain available during and after any postulated fire in the plant[2], when redundant trains of equipment required for hot shutdown are in the same fire area outside of the primary containment:

(1) separation of redundant trains by a fire barrier having a 3-hour rating

(2) separation of redundant trains by a horizontal distance of more than 6.1 meters (20 feet) containing no intervening combustible or fire hazards, together with fire detectors and an automatic fire suppression system

(3) separation of redundant trains by a barrier having a 1-hour rating, coupled with fire detectors and an automatic fire suppression system.

If any one of the above cannot be met, then Paragraph III.G.3 requirements must be met. Operator manual actions can be used to satisfy Paragraph III.G.1 [Ref. 1] requirements since these areas do not contain redundant safe shutdown trains. Operator manual actions are allowed to satisfy requirements in Paragraph III.G.3 in the performance of alternate or

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1 "Operator manual actions" are defined in the Glossary of this report. For this report, they do not include any actions within the MCR or the action(s) associated with abandoning the MCR in the case of a fire. Further, while the April 2001 edition of Regulatory Guide 1.189, "Fire Protection for Operating Nuclear Power Plants," had details on what constitutes hot shutdown for pressurized-water reactors (PWRs) and boiling-water reactors (BWRs), including the required systems, Revision 1 of Regulatory Guide 1.189, "Fire Protection for Nuclear Power Plants," issued March 2007 [Ref. 6], excludes that discussion and just identifies the Technical Specifications of each plant providing the definitions of hot shutdown and cold shutdown. This document is applicable to only those actions to achieve and maintain hot shutdown.

2 Similar guidance is incorporated into Section 9.5.1 of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Revision 4, issued October 2003 [Ref. 2], for plants licensed after January 1, 1979. These "post-1979" licensees incorporate their fire protection program implementation requirements into their operating license as a license condition and those requirements are largely the same as those from Appendix R that are discussed throughout this report.

dedicated shutdown activities. The NRC proposed rulemaking in SECY 03-0100, "Rulemaking Plan on Post-Fire Operator Manual Actions," issued June 2003 [Ref. 3], states that, under certain circumstances, operator manual actions may be a reasonable alternative to the separation requirements of Paragraph III.G.2, and many operator actions for operation of a hot shutdown train during a fire would not involve any safety-significant concerns.

The NRC developed Regulatory Issue Summary (RIS) 2006-10, "Regulatory Expectations with Appendix R, Paragraph III.G.2, Operator Manual Actions," dated June 30, 2006 [Ref. 4], which discusses acceptable means for achieving compliance with 10 CFR 50.48, "Fire Protection" [Ref.5]. Although the title is specific to Appendix R [Ref.1], the RIS applies to plants that were licensed to operate both prior and subsequent to January 1, 1979. Therefore, this report provides criteria for demonstrating the feasibility and reliability of operator manual actions in response to fire that are applicable to all plants. The NRC staff recognizes that certain criteria must be met to ensure that adequate safety is maintained as a result of the use of operator manual actions as an alternative to separation/protection. In particular, the NRC staff notes that such actions must be both feasible and reliable, especially considering that these actions are relied upon in lieu of passive fire barriers, distance, separation, and/or fire detectors and automatic fire suppression systems, each with relatively high reliability.

This document provides technical bases in the form of criteria and related technical information for justifying that operator manual actions are feasible and can reliably be performed under a wide range of plant conditions that an operator might encounter during a fire. If a large number of manual actions need to be addressed, it is expected that for many cases, where extra time is clearly available and the actions are relatively simple, evaluating the criteria will be straightforward, requiring only simple justifications and analysis. Furthermore, for the complex cases, licensees alternatively may choose to comply with the requirements of Appendix R [Ref. 1] by performing appropriate design changes. For these cases, the licensees have the option of submitting an exemption or license amendment request using detailed analyses of operator manual action feasibility and reliability.

This report, as a reference guide, addresses the feasibility and reliability of operator manual actions, from a deterministic approach, when used to achieve and maintain hot shutdown under fire conditions. It is planned that this document will be used by the NRC staff to support the review of operator manual actions, submitted by licensees as exemption requests. However, an operator manual action which meets the information provided in this report does not necessarily comply with NRC fire protection regulations. Additional considerations to ensure that adequate defense-in-depth such as fire detection and automatic suppression is maintained are addressed in Regulatory Guide 1.189 [Ref. 6] and should be considered when applying for an exemption or license amendment.

Operator manual actions, allowed by existing regulations to satisfy Paragraphs III.G.1 and III.G.3 of Appendix R to 10 CFR Part 50 [Ref. 1], are often identical actions and need to have the same feasibility and reliability goals as the Paragraph III.G.2 operator manual actions which require prior staff approval to ensure an adequate level of plant safety. Many operator manual actions used for alternative or dedicated shutdown have received prior staff review and

approval. This report will be used as information to review feasibility and reliability of *future*[3] postfire operator manual actions when staff review is required or requested.

Section 2 of this report explains the use of operator manual actions to ensure postfire hot shutdown, and discusses the purpose and scope of this report.

Section 3 summarizes each criterion, and discusses the basis for each.

Section 4 provides additional discussion of each criterion, as well as technical information for meeting the criteria.

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[3] Throughout this document words are *italicized* for emphasis

2. DISCUSSION

2.1 Background

This section provides a brief summary of key historical events leading to the need to address the acceptability of certain postfire operator manual actions and, ultimately, the information provided in this report.

Title 10, Paragraph 50.48, of the *Code of Federal Regulations* [Ref.5], requires each operating nuclear power plant to have a fire protection plan that satisfies Criterion 3, "Fire Protection," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 [Ref. 8]. Criterion 3 requires that SSCs important to safety must be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. The specific fire protection requirements for hot shutdown capability of a plant are further discussed in Section III.G of Appendix R to 10 CFR Part 50 [Ref. 1]. The more specific 10 CFR 50.48 [Ref. 5] and Appendix R requirements were added following a significant fire that occurred in 1975 at the Browns Ferry Nuclear Power Plant. That fire damaged control, instrumentation, and power cables for redundant trains of equipment necessary for hot shutdown.

In response to the fire, an NRC investigation revealed that the independence of redundant equipment at Browns Ferry was negated by a lack of adequate separation between cables for redundant trains of safety equipment. The investigators subsequently recommended that a suitable combination of electrical isolation, physical distance, fire barriers, and fixed automatic fire suppression systems should be used to maintain the independence of redundant safety equipment. In response to that recommendation, the NRC interacted with stakeholders for several years to identify and implement necessary plant fire protection improvements. In 1980, the NRC promulgated 10 CFR 50.48 [Ref. 5] to establish fire protection requirements and Appendix R to 10 CFR Part 50 [Ref. 1] for certain generic fire protection program issues, including Section III.G, which addresses fire protection of hot shutdown capability. The requirements for separation of cables and equipment associated with redundant hot shutdown trains within a fire area were promulgated in Paragraph III.G.2 of Appendix R for situations where fire area separation was not feasible (i.e., for plants already built or already designed).

Paragraph III.G.2 requires that cables and equipment of redundant trains of safety systems in the same fire area must be separated by one of the following provisions:

- a 3-hour fire barrier
- a horizontal distance of more than 6.1 meters (20 feet) with no intervening combustibles in conjunction with fire detectors and an automatic fire suppression system
- a 1-hour fire barrier combined with fire detectors and an automatic fire suppression system

Because the rule was to apply to facilities that were already built, the NRC realized that compliance with various parts of Appendix R might be difficult for certain fire areas such as the MCR and Cable Spreading Room at some facilities. Accordingly, the NRC included Paragraph III.G.3 to allow plants to credit dedicated or alternative safe shutdown equipment. There was also the provision to submit an exemption to seek NRC review and approval of alternative acceptable

methods for protecting safe shutdown. During implementation of the requirements of Appendix R, the NRC reviewed and approved a large number of exemptions for 60 licensees, including numerous exemptions from Paragraphs III.G.2 and III.G.3.

In the early 1990s, generic problems arose with Thermo-Lag[4] fire barriers, which many licensees were using as either a 1- or 3-hour fire barrier to comply with Paragraph III.G.2 of Appendix R. As a result, the NRC ultimately required plants to upgrade existing Thermo-Lag electrical raceway fire barrier systems or provide another means of compliance with Appendix R. Several years later, however, fire protection inspectors began identifying instances where some plants had not upgraded or replaced the Thermo-Lag fire barrier material or provided the required separation distance between redundant safety trains used to satisfy the criteria of Paragraph III.G.2. Some plants compensated for this by relying on operator manual actions, which were not reviewed and approved by the NRC through the exemption process established by 10 CFR 50.12, "Specific Exemptions" [Ref. 9]. Nonetheless, the NRC recognized that such actions may be an acceptable way of achieving hot shutdown in the event of a fire under certain conditions.

In 2002, the NRC informed the nuclear power industry that the use of unapproved manual actions was not in compliance with Paragraph III.G.2. During a meeting on June 20, 2002, the Nuclear Energy Institute (NEI) representative stated that there was widespread use of operator manual actions throughout the industry based on the understanding of past practice and existing NRC guidance. The industry representative also stated that the use of unapproved manual actions had become prevalent even before the concerns arose with Thermo-Lag material. Subsequent to the public meeting, the NRC developed criteria for inspectors to use in assessing the safety-significance of violations resulting from use of unapproved operator manual actions. Those criteria were based on past practice and experience by NRC inspectors reviewing operator manual actions to comply with Paragraph III.G.3 on alternative reactor shutdown capability. Plant staff members were familiar with these criteria through their interactions with the NRC staff during the implementation of the NRC inspection process. These criteria were issued in the revision to Inspection Procedure 71111.05, "Fire Protection," in March 2003 [Ref. 10].

Building on the above inspection criteria, the NRC considered it prudent to codify criteria for licensees and the NRC staff to use in evaluating the acceptability of operator manual actions used in lieu of meeting the separation criteria in Paragraph III.G.2 of Appendix R where redundant trains of safety systems exist in the same fire area. These criteria were to ensure that the actions were both feasible and reliable. These criteria would maintain safety by ensuring that thorough evaluations of the operator manual actions were performed comparable to evaluations for an exemption request. A rule change to incorporate these criteria was begun but later abandoned on the basis that the desired effect of significantly reducing the number of exemption requests seeking approval of the use of these operator manual actions would not be realized.

Nevertheless, the identified criteria continue to be valid for evaluating the acceptability of these operator manual actions. Contemplating numerous exemption requests by licensees seeking

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[4] Thermo-Lag is a brand name for a particular type of material used to construct fire barriers typically for protecting electrical conduits and cable trays. In the early 1990s, issues arose regarding the testing and qualification process used for this material. It was determined that barriers made of this material would not provide protection for the required periods of time.

approval for such actions, the NRC staff considered it important to document these criteria and related information for use by the staff when evaluating the exemption requests. To meet that need, this report provides additional technical information, primarily for NRC staff, but also considered useful to the industry, for ensuring the feasibility and reliability of operator manual actions, from a deterministic approach, for post-fire hot shutdown.

2.2 Purpose of this Report

Most of the criteria provided herein are based on reviews of existing work related to modeling human behavior in responses to fires and other accident conditions in nuclear power plants. For example, most of the factors covered by the criteria were derived from reviews of selected fire analyses conducted as part of individual plant examinations of external events (IPEEEs), the IPEEE summary report (NUREG-1742, "Perspectives Gained From the Individual Plant Examination of External Events (IPEEE) Program," Volumes 1 and 2, issued April 2002 [Ref. 11]), previous reviews of fire-related operational events to identify important factors influencing human performance in fires [e.g., Refs. 12–14], lessons learned from the development of human reliability analysis (HRA) criteria for use in the ongoing fire requantification studies jointly conducted by the NRC and the Electric Power Research Institute (EPRI) [Ref. 15], general HRA methods such as Simplified Plant Analysis Risk—Human Reliability Analysis (SPAR-H) [Ref. 16] and A Technique for Human Event Analysis (ATHEANA) [Ref. 17], and information on operator response times and time response design criteria for safety-related operator actions [e.g., Refs. 18 and 19]. Examples of the general factors covered by the criteria (discussed in detail in Sections 3 and 4 of this report) include the availability of indications for the actions, environmental considerations, staffing and training, communications, availability of necessary equipment, and availability of procedures.

While the importance of such factors is generally obvious, determining exactly how to implement and evaluate the factors can be somewhat less straightforward and subject to interpretation. For example, what should be covered by procedures appropriate for operator manual actions, and what type of training is appropriate? One of the main purposes of this document is to provide additional technical information related to the factors as a means to address the acceptability of postfire manual actions using a deterministic approach.

This technical information is aimed at ensuring that operator manual actions are both feasible and reliable. Among the criteria provided herein is the need for time-authenticated demonstrations of the manual actions (involving actual execution of actions to the extent possible) and adequate time available to complete the actions before fire-induced consequences occur that would otherwise prevent achieving and maintaining hot shutdown. Showing, with a demonstration (as subsequently discussed in Sections 3 and 4 of this report), that actions meeting the criteria can be completed in the available time, documents the feasibility; however, additional issues must be considered to show that the actions can reliably be performed, by different crews, under the variety of conditions that could occur during a fire.

For example, fire factors which may not be possible to create for the demonstrations could cause further delay under actual fire conditions (i.e., the demonstration would likely fall short of actual fire situations). Hence, although a demonstration shows that a manual action can be performed within the necessary time, shortcomings of the demonstration may mean that under an actual fire situation, other possible delays not addressed by the demonstration may need to

be accounted for. Furthermore, typical and expected variability between individuals and crews could lead to variations in operator performance (human-centered factors). Finally, variations in the characteristics of the fire and related plant conditions could alter the time available for the operator actions.

Hence, to ensure that actions can be performed reliably, and in concert with the safety margin philosophy inherent in the NRC's regulations as well as good engineering practice, the technical information provided herein also addresses the subject of performing analyses (or providing equivalent justification) useful to confirming that adequate time is available for the actions. The information strives to ensure that relevant factors are considered in determining or justifying time adequacy (which can be justified in different ways as subsequently addressed in Section 4 of this report) and that the process for determining the time available for the actions addresses the potential variations in fire characteristics and plant conditions.

As to the aforementioned analysis, and as delineated in greater detail in subsequent sections, determining whether there is enough time available to perform the operator manual action should account for potential circumstances, such as (1) the potential need to recover from or respond to unexpected difficulties associated with instruments or other equipment, or communication devices, (2) environmental and other effects that are not easily replicated in a demonstration, such as radiation, smoke, toxic gas effects, and increased noise levels, (3) limitations of the demonstration to account for all possible fire locations that may lead to the need for such operator manual actions, (4) inability to show or duplicate the operator manual actions during a demonstration because of safety considerations while at power, and (5) individual operator performance factors, such as physical size and strength, cognitive differences, and the effects of stress and time pressure. The time available should not be so restrictive relative to the time needed to perform the actions that personnel are not able to recover from any initial slips or errors in conducting the actions (i.e., there is some "recovery" time built in, should it be needed). Establishing that adequate time is available is more easily justified using demonstrations of the operator manual actions with clear illustration that appropriate calculations of the time available have been conducted. Sections 3 and 4 of this report provide further details regarding what should be considered in substantiating that adequate time is available to ensure the reliability of the operator manual actions.

As a final note, this report specifically addresses a deterministic approach for assessing the feasibility and reliability of operator manual actions. However, risk assessment and particularly human reliability techniques may be useful when identifying the range of fire scenarios and related contexts as well as the possible operator manual actions that might be used in response to possible fire scenarios. Hence, the use of such risk-related techniques as an aid in addressing the criteria presented herein is not discouraged, but the use of these techniques is neither required nor expected. Ultimately, using this information, the operator manual actions should meet the applicable deterministic criteria provided herein for feasibility and reliability.

2.3 Scope of this Report

This report provides technical information to assist the NRC staff in determining that operator manual actions are feasible and can be performed reliably in response to fire. The readers should refer to Regulatory Guide 1.189 [Ref. 6] for details on how the NRC staff plans to use this information in its reviews.

While this report strives to provide enough information to support this determination about the feasibility and reliability of manual actions, it does not attempt to cover in detail all possible aspects of how to meet the criteria that are provided herein. This report focuses on *unique* aspects of the hazard involved (fire) and the potentially unique characteristics of subsequent manual actions during the operators' response. Hence, for instance, it is not the intent of this report to specify in detail what constitutes "adequate procedures." Many other guidance documents and an evolving consensus address this issue. Additionally, each plant has a well-established program for identifying, writing, reviewing, issuing, and changing procedures. What is provided here is information on the unique aspects of fire and the associated operator manual actions.

Finally, for purposes of this report, the two types of operator manual actions covered by this technical information are (1) *preventive* actions and (2) *reactive* actions, as defined in the Glossary of this report.

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3. BASES FOR THE FEASIBILITY AND RELIABILITY CRITERIA

3.1 Overview

This section presents the criteria for evaluating the feasibility and reliability of operator manual actions. Each criterion is briefly introduced, and the bases that support the need for each criterion are also provided. Technical information for implementing each criterion is covered in Section 4 of this report.

The following provides a definition (also in the Glossary) of "operator manual actions" as the term is used herein:

> Operator manual actions are those actions performed by operators to manipulate components and equipment from outside the MCR to achieve and maintain postfire hot shutdown, but do not include "repairs." Operator manual actions comprise an integrated set of actions needed to help ensure that hot shutdown can be accomplished, given that a fire has occurred in a particular plant area.

The NRC's feasibility and reliability criteria for operator manual actions are summarized below:

- An analysis should be prepared to evaluate the feasibility and reliability of operator manual actions. The *analysis* should determine that adequate time exists for the operator to perform the required manual actions to achieve and maintain hot shutdown from a single fire. The *adequate time* should reasonably account for all important variables, including (1) differences between the analyzed and actual conditions, and (2) human performance uncertainties that may be encountered.
- The analysis should show that the actions can be performed under the expected *environmental factors* that will be encountered.
- The analysis should show that (1) the *functionality of equipment and cables* needed to implement operator manual actions to achieve and maintain hot shutdown will not be adversely affected by the fire, and (2) the equipment will be *available* and readily *accessible* consistent with the analysis. In addition to the SSCs needed to directly perform the desired actions, other supporting equipment may also be required, including (to the extent required for successful performance of each operator manual action)—
  - *indications* necessary to show the need for the manual actions, enable their performance, and verify their successful accomplishment (if not directly observable)
  - necessary *communications*
  - necessary *portable equipment*
  - necessary *personnel protection equipment*
- There should be plant *procedures* covering each operator manual action required to achieve and maintain hot shutdown and *training* for each operator on the procedures.
- The *number of available personnel (staffing)*, exclusive of Fire Brigade members, needed to perform the actions should be consistent with the analysis.

- There should be periodic *demonstrations* of the manual actions, consisting of actual executions of the relevant actions to the extent sufficient to show continued proficiency in performing the actions.

The above criteria provide a means to determine that there is reasonable assurance that the actions are feasible and can be performed reliably to bring the plant to a hot shutdown condition, thereby protecting public health and safety. The above criteria are considered appropriate to achieve the overall requirement that the actions should be both feasible and reliable.

Any analysis of the feasibility and reliability of an operator manual action, or combination of such actions, begins with definition of the time available to complete the action(s). Typically, this dictates the degree of rigor needed for the rest of the analysis and the extent to which the various criteria need to be addressed. Since determination of the time to accomplish the action is inherent in developing the complete timeline, when accounting for fire effects, the analyst or reviewer will need to address the criteria that are applicable. However, not all of the criteria will usually require significant analysis or even be applicable, particularly for the simpler and more straightforward actions.

Suppose it was determined, based, for example, on an evaluation of the physical response of the plant to the transient that is potentially induced by the fire, that there is sufficient time available to complete an action (e.g., several hours). Assuming there are no "unique" aspects of the fire that could prolong its extinguishment unduly (e.g., an oil fire that is continuously fed by an oil leak, such that extinguishment is impossible until the leak can be stopped), and the proposed operator manual actions can be shown to be relatively straightforward and easily justified as unimpeded by the fire or its effects, including firefighting activities, one would expect that the various feasibility and reliability criteria can be shown to be met with very simple justifications or analysis. Some may not even be applicable, for example, there may be no need for special tools or "staged" equipment. Under such circumstances, one would expect a relatively simple analysis and review. Implicit would be an expectation of minimal variability and uncertainty along with a large "time margin." In such a case, for example, demonstration of the action may be easily justified as enveloped by some other action that is more rigorously demonstrated.

At the other extreme, suppose the time available is relatively short (tens of minutes, at most), the operator manual actions are not straightforward or are somewhat complex (or may involve multiple operators or the same operator performing multiple actions), or there are "unique" aspects to the fire making rapid extinguishment difficult (e.g., a reluctance to apply water to an electrical fire due to personnel safety considerations, such as the potential for high-voltage shocks[5]). Under such conditions, much more rigorous analysis and review are likely to be needed to account for all the criteria and how well each is met given the fire and its effects, including firefighting activities. It is certainly conceivable that, given the inherently greater variability and uncertainty present in such a situation, along with the inevitably short, if any,

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[5] While this does not a priori include traditional reluctance to apply water to electrical fires, even when no personnel safety concern is involved, it should still be recognized that there may be such reluctance among some personnel, especially those not members of the Fire Brigade, such that time delays in extinguishment could be involved.

"time margin," that a deterministic evaluation using the criteria in this NUREG is not possible (due to the limits of the "all-or-none" nature of deterministic analysis).

The following subsections elaborate on the bases for each of the feasibility and reliability criteria. It should be noted that, in some cases, the various regulations and documents (e.g., NUREG-series reports) that are discussed below to provide a basis for the criteria are not necessarily tied directly to regulations that apply to specific plants, including the "pre-1979" plants (i.e., plants licensed to operate before January 1, 1979). The intent of the discussions, and the associated citations, is to illustrate that there is a defensible basis for why the various criteria are appropriate (i.e., the various factors and conditions they address represent sound practices that have already been identified as generally important to safety).

3.2 Summary of Bases for Feasibility and Reliability Criteria

3.2.1 Analysis Showing Adequate Time Available to Perform the Actions (To Address Feasibility)

This criterion addresses the need for an analysis to determine that there is adequate time available for the operator to perform the required manual actions to achieve and maintain hot shutdown after a single fire. The analysis should determine that the time available is long enough to allow the action to be diagnosed and executed. If a demonstration of the action (discussed in Section 3.2.11 below) shows that it can be diagnosed and accomplished in the time available, and uncertainties in estimating the time available have been considered (see Section 4.2.1 of this report), then the action can be regarded as feasible to achieve and maintain hot shutdown. To establish reliability, however, the uncertainties associated with estimating how long it takes to diagnose and execute operator manual actions (see Sections 3.2.2 and 4.2.2 of this report) should also be considered.

This criterion is based upon regulations requiring that a nuclear power plant must always be maintained in a safe condition, even following accidents, consistent with the additional restriction that a hot shutdown state be reached and maintained, in accordance with Section III.G of Appendix R to 10 CFR Part 50 [Ref. 1]. Implicit in these requirements is the analysis of the plant's thermal-hydraulic response, including the time needed to fulfill the listed safety functions.

This criterion is not a new NRC staff view in that previous NRC staff reviews and approvals of postfire operator manual actions included the consideration of whether there was adequate time for the operator manual actions, based on the progression of the fire and the thermal-hydraulic conditions of the plant. Additionally, this criterion is consistent with current inspection criteria for fire protection manual actions [Ref. 10] under the verification and validation criterion, ensuring that plant staff has adequately evaluated the capability of operators to perform the manual actions in the time available. These existing practices and the associated expectations support the need for a criterion that addresses the assurance that there is adequate time to perform the operator manual actions.

3.2.2 Analysis Showing Adequate Time Available to Ensure Reliability

This criterion addresses the reliability of the operator manual actions. For a feasible action to be performed reliably, it should be shown that there is adequate time available to account for uncertainties not only in estimates of the time available, but also in estimates of how long it takes to diagnose and execute the operator manual actions (e.g., as based, at least in part, on a plant demonstration of the action under nonfire conditions). It should be shown that there is extra time available to account for such uncertainties. This extra time is a surrogate for directly accounting for sources of uncertainty, such as the following, inherent in estimating the time available for the action and the time required:

(1) variations in fire and related plant conditions that could affect the time estimates (e.g., fast energetic fire failing equipment quickly vs. slow developing fire with little or no equipment failures for some time, variable fire detector response times and sensitivities, variable air flows affecting the fire and its growth, specific fire initiation location relative to important targets, presence (or not) of temporary transient combustibles)

(2) factors unable to be recreated in the demonstrations, or in some cases not anticipated for an actual fire situation, that could cause further delay in the time it could take to perform the operator manual actions under actual fire conditions (i.e., where the demonstration may likely fall short of actual fire situations), as in the following examples:

- The operators may need to recover from/respond to unexpected difficulties, such as problems with instruments or other equipment (e.g., locked doors, a stiff handwheel, or difficulty with communication devices). Such difficulties can and sometimes do happen and represent a possible uncertainty in how long it will take to perform an action. The extra time would make it unlikely that difficulties encountered in an actual fire situation will prevent the desired manual actions from being accomplished in a timely manner.

- Environmental and other effects might exist that are not included as part of the simulation in the demonstration, such as radiation (e.g., the fire could reasonably damage equipment in a way such that radiation exposure could be an issue at the location in which the action needs to be taken, requiring the operator to don personnel protection clothing, which takes extra time, but which may not be included in the demonstration); smoke and toxic gas effects which are not likely to be actually simulated in the demonstration (e.g., in a real fire manual for actions needed to be performed near the fire location, although in a separate room, there may be smoke and gas effects that could slow the implementation time for the action); increased noise levels from the fire and the operation of suppression equipment and from personnel shouting instructions; water on the floor possibly delaying personnel movements; obstruction from charged fire hoses; increased heat and humidity resulting from fire-induced loss of heating, ventilation, and air conditioning (heat stress); or too many people getting in each others' way. Again, all these may not actually be simulated, but should be considered as possible, and perhaps even likely, when determining the time it may take to perform the manual action in a real situation.

- The demonstration might be limited in its ability to account for (or envelop) all possible fire locations where the actions are needed and for all the different

travel paths and distances to where the actions are to be performed. A similar limitation concern is that the current location and activities of needed plant personnel when the fire starts could delay their participation in executing the operator manual actions (e.g., they may typically be at a location that is on the opposite side of the plant relative to a postulated fire location and/or may need to restore certain equipment before being able to participate such as if they are routinely doing maintenance). The intent is not to address temporary/infrequent situations but to account for those that are typical and may impact the timing of the action.

- It may not be possible to execute relevant actions during the demonstration because of normal plant status and/or safety considerations while at power (e.g., operators cannot actually operate the valve using the handwheel, but can only simulate doing so).

(3) typical and expected variability between individuals and crews leading to variations in operator performance (i.e., human-centered factors), as in the following examples (given the likely experience and training of plant personnel performing the actions, it need not be assumed that these characteristics would lead to major delays in completing the actions, but their potential effects should be considered in the specific fire-related context of the actions being performed, to confirm this assumption):

- physical size and strength differences that may be important for the desired action
- cognitive differences (e.g., memory ability, cognitive style differences)
- different emotional responses to the fire and/or smoke
- different responses to wearing self-contained breathing apparatuses (SCBAs) to accomplish a task, that is, some people may be less comfortable wearing an SCBA face piece (e.g., obscured vision) than other people
- differences in individual sensitivities to "real-time" pressure
- differences in team characteristics and dynamics

The emphasis on adequate time for operator manual actions is consistent, conceptually, with ANSI/ANS-58.8-1994, "American National Standard Time Response Design Criteria for Safety-Related Operator Actions," issued 1994 [Ref. 18], on time response design criteria for safety-related operator actions. That standard established "time response criteria...[that] adopt time intervals...to ensure that adequate safety margins are applied to system and plant design and safety evaluations." The standard recognized that "in actual practice, the operator should be capable of reacting to design-basis events correctly and performing the safety-related operator actions in less time than specified by the criteria in this standard." While this standard was not specifically intended for the actions addressed in this document, the concept embodied in the standard of having adequate time contributes to ensuring the reliability of operator manual actions.

To account for the above variables and uncertainty, it is prudent to determine that adequate time exists when comparing the calculated time available and the time required to perform the action. There are different ways to determine that there is adequate time, as is discussed in Sections 4.2.1 and 4.2.2 of this report. Determining that adequate time is available, accounting for the above variables and uncertainty, along with meeting all the other feasibility and reliability

criteria, should provide reasonable assurance that the operator manual actions can reliably be performed under a wide range of conceivable conditions by different plant crews.

3.2.3 Environmental Factors

This criterion addresses the issue that environmental conditions may affect personnel's mental or physical performance of operator manual actions to the extent that, if the actions are not entirely precluded, they could be severely degraded. The expected environmental conditions need to be considered in both the locations where the operator manual actions will be performed and along the access and egress routes. Personnel performance can be degraded, if not precluded, by the inability to reach the location as well as the inability to perform the action in the conditions existing at the location. The environment along the egress route after completion of the operator manual action should also be considered to ensure personnel health and safety throughout.

Environmental factors are those factors that could negatively impact the ability to perform the manual actions, including radiation, lighting, temperature, humidity (caused, for instance, by water from sprinkler operation), smoke, toxic gases, and noise.

That these factors need to be considered follows from such requirements as 10 CFR Part 20, "Standards for Protection Against Radiation," governing radiation exposure in responding to fires [Ref. 20]. As stated in Appendix A to 10 CFR Part 50, "anticipated operational occurrences mean those conditions of normal operation which are expected to occur one or more times during the life of the nuclear power unit...." Fires fall into this category and, therefore, are subject to regulations governing "normal operation," such as 10 CFR 20.1201. Similarly, ANSI/ANS-51.1, "American National Standard Nuclear Safety Criteria for the Design of Stationary Pressurized-Water Reactor Plants" [Ref. 21], and its counterpart, ANSI/ANS-52.1, "American National Standard Nuclear Safety Criteria for the Design of Stationary Boiling Water Reactor Plants" [Ref. 22], consider that a "fire limited to one fire area" (corresponding to "plant condition 2") occurs with a frequency of at least once per year. An event in this frequency range is considered part of "normal operation."

Further, NUREG-0800, Section 9.5.1 [Ref. 2], states that "the strategies for fighting fires in all safety-related areas and areas presenting a hazard to safety-related equipment...should designate...potential radiological and toxic hazards in fire zones; ...ventilation system operation that ensures desired plant air distribution when the ventilation flow is modified for fire containment or smoke clearing operation; ...most favorable direction from which to attack a fire in each area in view of the ventilation direction, access hallways, stairs, and doors that are most likely to be free of fire, and the best station or elevation for fighting the fire." This specific reference is not directly applicable to operator manual actions but applies to firefighting activities that are *not* the subject of this document. However, if, for instance, operator manual actions may need to be performed at locations where potential hazards may exist or specific access paths are recommended to deal with potential environmental concerns, some of this information could be useful for operator manual actions as well. Therefore, the reference is included as a basis.

Emergency lighting is addressed in Section III.J of Appendix R to 10 CFR Part 50 [Ref. 1], or by the plant's approved fire protection program, as well as in NUREG-0800, Section 9.5.1 [Ref. 2],

where it is stated that "[l]ighting...[is] vital to safe shutdown and emergency response in the event of a fire."

Studies such as NUREG/CR-5680, "The Impact of Environmental Conditions on Human Performance," Volumes 1 and 2, issued September 1994 [Ref. 23], attest to the impact on human performance of such variables as heat and cold, noise, lighting, and vibration. NUREG-1764, "Guidance for the Review of Changes to Human Actions," issued February 2004 [Ref. 24], cited in NUREG-0800, Section 18.0, Revision 1, February 2004 [Ref. 7], notes that "...[q]ualitative assessment [of the human actions] addresses...the environmental challenges...that could negatively affect task performance...." Experimental studies, such as the ones cited as References 25 and 26, provide further evidence of the effects of heat and cold stresses on the performance of various physical and cognitive human tasks. NUREG-0711, "Human Factors Engineering Program Review Model," Revision 1, issued February 2004 [Ref. 27], also cited in NUREG-0800, Section 18.0 [Ref. 7], states that "[human-system interface] characteristics should support human performance under the full range of environmental conditions, e.g., normal as well as credible extreme conditions...." Accordingly, it needs to be ensured that such habitability issues (including those that may be unique to fire conditions such as additional heat concerns, smoke, toxic gases, effects of ventilation shutdown, the possibility of having to pass through areas and/or manipulate electrical equipment with water on the floor) will not adversely impact the operator manual actions in the locations where the actions are to be taken and along access and egress routes. Experimental studies, such as those cited in References 28 and 29, provide further evidence of the effects of carbon dioxide, for example, on various measures of human performance.

The importance of this criterion is also consistent with current inspection criteria for fire protection manual actions under the environmental considerations' criterion. Current inspections ensure that plant staff has addressed radiation levels per 10 CFR Part 20 [Ref. 20], lighting, temperature and humidity, and fire effects such as smoke and toxic gases. This existing practice and the associated expectations support the need for a criterion that addresses the environment in which the operator manual actions will be performed.

3.2.4 Equipment Functionality and Accessibility

This criterion addresses the need to ensure that the equipment that is necessary to enable implementation of an operator manual action to achieve and maintain postfire hot shutdown is accessible, available, and not damaged or otherwise adversely affected by the fire and its effects (such as heat, smoke, water, combustible products, spurious actuation). Plant SSCs are the means by which hot shutdown conditions are achieved and maintained. Systems and components often require active intervention, through either automatic or manual means, to perform their function. Hence, equipment that may involve operator manual actions to perform its hot shutdown function needs to be identified and verified to be both accessible and functionally available to the extent required to successfully implement the operator manual actions.

Information Notice (IN) 92-18, "Potential for Loss of Remote Shutdown Capability During a Control Room Fire," dated February 28, 1992 [Ref. 30], identifies the type of functionality issue that should be considered. For example, the bypassing of thermal overload protection devices for motor-operated valves (MOVs) (discussed in Regulatory Guide 1.106, "Thermal Overload

Protection for Electric Motors on MOVs," issued March 1977 [Ref. 31]) could jeopardize completion of the safety function or degrade other safety systems due to sustained abnormal circuit currents that can arise from fire-induced "hot shorts." Even if the overload protection devices are not bypassed, hot shorts can cause loss of power to MOVs by tripping the devices. If an operator manual action involves the manual manipulation of a powered MOV, such fire-induced damage (e.g., overtorquing a MOV) could render manipulation physically impossible. Other equipment could also have fire-damage-susceptible parts. Therefore, if equipment (including cabling and power and cooling to support the equipment) that could be affected by the fire or its subsequent effects are planned for use via operator manual actions, the plant staff should verify that the functionality of that equipment will not be adversely affected and the function can be successfully accomplished by manual actions.

Accessibility to these systems and equipment is necessary to enable personnel to perform the operator manual actions on the components. Not only must the personnel be able to find and reach the locations of the components, but they also must be able to perform the required action on the components.

The importance of this criterion is also consistent with current inspection criteria for fire protection manual actions under the accessibility criterion and other related criteria. Current inspections ensure, for instance, that the necessary equipment is available and protected from fire effects. This existing practice and the associated expectations support the need for a criterion that addresses the functionality and accessibility of equipment needed to successfully perform operator manual actions.

3.2.5 Available Indications

In addition to the SSCs needed to directly perform the desired functions, the equipment needs to include diagnostic indications relevant to the desired operator manual actions. These indications, to the extent required by the nature of the operator manual action, may be needed to (1) enable the operators to determine which manual actions are appropriate for the fire scenario, (2) direct the personnel performing the manual actions, and (3) provide feedback to the operators, if not already directly observable, to verify that the manual actions have had their expected results and the manipulated equipment will remain in the desired state. These indications include those necessary to detect and diagnose the location of the fire. As necessary equipment, indications should also meet the functionality and accessibility criterion discussed above.

This indication criterion is consistent with the guidance in Generic Letter (GL) 81-12, "Fire Endurance Test Acceptance Criteria for Fire Barrier Systems Used to Separate Redundant Safe Shutdown Trains Within the Same Fire Area (Supplement 1 to Generic Letter 86-10: Implementation of Fire Protection Requirements" [Ref. 32], regarding manual actions for associated circuit resolution for alternative shutdown (Paragraph III.G.3 of Appendix R to 10 CFR Part 50 [Ref. 1]):

> For circuits of equipment and/or components whose spurious operation would affect the capability to safely shutdown...provide a means to detect spurious operations and then [provide] procedures to defeat the maloperation of equipment (i.e., closure of the block valve if (a power-operated relief valve

(PORV)) spuriously operates, opening of the breakers to remove spurious operation of safety injection).

The adequacy of indications to detect the need for an action (in this example, spurious operations) illustrates the basic concept of needing sufficient indications so that (1), (2), and (3) in the previous paragraph can be performed.

Section IX of Attachment I to IN 84-09, "Lessons Learned From NRC Inspection of Fire Protection Safe Shutdown Systems (10 CFR 50, Appendix R)," dated March 7, 1984 [Ref. 33], lists the minimum monitoring capability, which includes (1) diagnostic instrumentation for shutdown systems, (2) level indication for all tanks used, (3) pressurizer (PWR) or reactor water (BWR) level and pressure, (4) reactor coolant hot-leg temperatures, or core exit thermocouples, and cold-leg temperatures (PWR), (5) steam generator pressure and level (wide range, PWR), (6) source range flux monitor (PWR), (7) suppression pool level and temperature (BWR), and (8) emergency or isolation condenser level (BWR). However, annunciators, indicating lights, pressure gauges, and flow indicators are among the instruments typically not protected under the guidance in IN 84-09, although these instruments may be needed to detect that a maloperation or other trigger for action has occurred. IN 84-09 does not exclude other alternative methods of achieving hot shutdown. Plant staff may employ alternative instrumentation to help achieve hot shutdown (e.g., boron concentration indication).

The importance of providing more indication than recommended in IN 84-09 [Ref. 33] was recognized when the NRC updated its inspection guidance in March 2003 [Ref. 10] for operator manual actions. "Determine whether adequate diagnostic instrumentation,[6] unaffected by the postulated fire, is provided for the operator to detect the specific spurious operation that occurred." Suppose a plant has protected only the instrumentation needed to conform to IN 84-09. If due to lack of circuit protection, the plant staff has to respond to an inappropriate equipment operation (e.g., decreasing pressurizer level), additional diagnostic instrumentation needs to be sufficient for the operator to direct the correct response. For example, the decreasing pressurizer level could be due to spurious closure of an in-line MOV. If so, which one? The plant's fire protection safe shutdown analysis should consider the means to determine the source of the problem, if that is necessary to identify the correct operator action.

The importance of available indication is also covered in such documents as NUREG-1764 [Ref. 24] and NUREG-0711 [Ref. 27], which are cited in NUREG-0800, Section 18.0 [Ref. 7]. NUREG-1764 states that "...a description should be provided for...parameters that indicate that the high-level function is available...operating[, and]...achieving its purpose.... [C]onsider not only the personnel role of initiating manual actions but also responsibilities concerning automatic functions, including monitoring the status of automatic functions to detect system failures...." NUREG-0711 discusses the need to "...provide evidence that the integrated system adequately supports plant personnel in the safe operation of the plant.... The objectives should be to...validate that, for each human function, the design provides adequate alerting, information, control, and feedback capability for human functions to be performed under normal plant evolutions...[and] transients."

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6 Defined in GL 86-10, "Implementation of Fire Protection Requirements," dated April 24, 1986 [Ref. 34], as "instrumentation beyond that previously identified in IN 84-09 needed to ensure proper actuation and functioning of safe shutdown and support equipment (e.g., flow rate, pump discharge pressure)."

3.2.6 Communications

In addition to the SSCs needed to directly perform the desired functions, equipment to support communications among personnel may be needed to ensure proper performance of the operator manual actions. For instance, besides the use of face-to-face communication, implementation of an operator manual action may need the use of two-way radios or other electronic or powered forms of communication. In these cases, such equipment may be essential to providing feedback between operators in the MCR and personnel out in the plant, as well as between personnel in different locations of the plant. This communications equipment may then be needed to ensure that any activities requiring coordination among them are clearly understood and correctly accomplished. Further, the unpredictability of fires can force staff to deviate from planned activities (hence, the need for effective, and in some cases, constant communications). Communications permit the performance of sequential operator manual actions (where one set of actions must be completed before another set can be started) and provide verification that procedural steps have been accomplished, especially those that must be conducted at remote locations. Therefore, effective communications equipment, to the extent it is needed, should be readily available and meet the functionality and accessibility criterion covered in Section 3.2.4 above.

The need to emphasize communications equipment is cited, for instance, in NUREG-0800, Section 9.5.1 [Ref. 2], which states "...two-way voice communication...[is] vital to safe shutdown and emergency response in the event of a fire. Suitable...communication devices should be provided...." Further, NUREG-0800, Section 18.0 [Ref. 7], references NUREG-1764 [Ref. 24], NUREG-0711 [Ref. 27], and NUREG-0700, "Human-System Interface Design Review Guidelines," Revision 2, issued May 2002 [Ref. 35], which state that "qualitative assessment [of the human actions] addresses...the level of communication needed to perform the task.... When developing functional requirements for monitoring and control capabilities that may be provided either in the control room or locally in the plant, the following...should be considered: ...communication, coordination...workload [and] feedback." Examples cited include "loudspeaker coverage...page stations...personal page devices suitable for high-noise or remote areas...[and] communication capability...for personnel wearing protective clothing [such as] voice communication with masks...." Experimental studies, such as the ones cited in Reference 36, provide further evidence of the effect of respirators on human task performance.

The importance of this criterion is also consistent with current inspection criteria for fire protection manual actions under the communications criterion. Current inspections ensure that the communications capability will be protected from the effects of a postulated fire. This existing practice and the associated expectations support the need for a criterion that addresses communications needed to successfully perform operator manual actions.

3.2.7 Portable Equipment

In addition to the SSCs needed to directly perform the desired functions, the equipment needed to successfully implement the operator manual actions may also include portable equipment relevant to the operator manual actions. Portable equipment, especially unique or special tools (such as keys to open locked areas or manipulate locked controls, flashlights, ladders to reach high places, torque devices to turn valve handwheels, and electrical breaker rackout tools), can be essential to access and manipulate SSCs to successfully accomplish operator manual actions. Hence, to the extent this equipment is needed to successfully implement the operator manual action, this equipment should be readily available and its location should be known and constant. This equipment should be in working order (functional) and access to this equipment should be unimpeded so that it will not delay the operator manual actions and functional.

The importance of this criterion is consistent with current inspection criteria for fire protection manual actions under the special tools criterion ensuring that such equipment is dedicated and available. This existing practice and the associated expectations support the need for a criterion that addresses the use of portable equipment needed to successfully perform operator manual actions.

3.2.8 Personnel Protection Equipment

Besides the SSCs needed to directly perform the desired functions, the equipment needed to successfully implement the operator manual actions may also include personnel protection equipment relevant to the operator manual actions, such as protective clothing, gloves, and SCBAs. Such equipment may need to be worn, for example, to permit access to and egress from locations where the operator manual actions must be performed since the routes could be negatively affected by fire effects, such as smoke that propagate beyond the immediate fire area. Hence, to the extent it is needed to successfully implement the operator manual action, access to this equipment should be unimpeded so that it will not delay the operator manual actions, and this equipment needs to be in working order (e.g., an SCBA must provide a tight seal against any smoke ingress, be in working order when donned, and not malfunction while being used).

NUREG-0800, Section 18.0 [Ref. 7], references NUREG-0700 [Ref. 35], which supports the need to consider this equipment by stating, "[t]he operation of controls should be compatible with the use of protective clothing, if it may be required.... The likelihood of operators requiring protection...is greater outside the control room."

Further, current inspection guidance treats this equipment as subject to the special tools criterion cited previously.

3.2.9 Procedures and Training

This criterion reflects the need for written, maintained plant procedures that cover all the manual actions and the need for each operator who might be required to perform the actions to achieve and maintain hot shutdown to receive training on these manual actions. The role of written plant procedures in the successful performance of operator manual actions is threefold:

(1) They assist the operators in correctly diagnosing the type of plant event that the fire may trigger (usually in conjunction with indications), thereby permitting the operators to select the appropriate operator manual actions.

(2) They direct the operators to the appropriate preventive and mitigative manual actions.

(3) They minimize the potential confusion that can arise from fire-induced conflicting signals, including spurious actuations, thereby minimizing the likelihood of personnel error during the required operator manual actions. Written procedures contain the steps of what needs to be done, and unless it can be argued to be "skill-of-the-craft," they should also contain guidance for how and where it should be done, and what tools or equipment should be used.

Training on these procedures serves three supporting functions—(1) it establishes familiarity with the fire procedures and equipment needed to perform the desired actions, as well as, potential conditions in an actual event, (2) it provides the level of knowledge and understanding necessary for the personnel performing the operator manual actions to be well prepared to handle departures from the expected sequence of events, and (3) it gives personnel the opportunity to practice their response without exposure to adverse conditions, thereby enhancing confidence that they can reliably perform their duties in an actual fire event.

With regard to plant procedures, in general, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50 [Ref. 37] requires quality assurance procedures for nuclear power plants:

> Activities affecting quality shall be prescribed by documented instructions [or] procedures...of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Instructions [or] procedures...shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Appendix A to Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)," issued February 1978 [Ref. 38], on quality assurance programs for power operation describes a method acceptable to the NRC staff for complying with these Appendix B requirements. Appendix A to the regulatory guide identifies the following as typical safety-related activities that should be covered by written procedures—(1) the plant fire protection program (administrative procedures), (2) mode change from plant shutdown to hot standby and operation at hot standby (general plant operating procedures), (3) changing modes of operation for a wide range of safety-related PWR and BWR systems (specific plant operating procedures), and (4) plant fires (procedures for combating emergencies and other significant events). In addition, there should be procedures for abnormal, off-normal, and alarm conditions, with each safety-related annunciator having its own written procedure. In

conformance with the above, procedures covering operator manual actions in response to fire should be controlled procedures such as those covering other plant operations. The training portion of this criterion is an extension of the requirement of 10 CFR 50.120, "Training and Qualification of Nuclear Power Plant Personnel" [Ref. 39], that nuclear power plant personnel is trained and qualified. "Each nuclear power plant licensee...shall establish, implement, and maintain a training program derived from a systems approach to training as defined in 10 CFR 55.4 [Operators' Licenses—Definitions, Ref. 40].... The training program must incorporate the instructional requirements necessary to provide qualified personnel to operate and maintain the facility in a safe manner in all modes of operation."

The personnel performing operator manual actions (operators, maintenance staff, electrical technicians) need to undergo training for their individual responsibilities. Existing plant training programs should largely address many of the training issues, such as ensuring instruction is provided by qualified individuals, that it is provided to all personnel who may be required to perform operator manual actions, and that practice sessions are held consistent with the requirements for training on other abnormal procedures for each member of the operating crews that could be involved in diagnosing or performing the actions. This will provide them with experience in performing the operator manual actions.

In addition, as discussed below in the demonstration sections of this report (i.e., Sections 3.2.11 and 4.2.11), there may be some actions that need to be practiced under as realistic conditions as possible, on a regular basis, by all crews (i.e., the actions need to be demonstrated on a regular basis to ensure that they can be performed reliably). For these operator manual actions, actual demonstrations of the actions, under conditions as closely approximating actual fire situations as is reasonable, should become part of the regular training program.

Drills for operator manual actions should address such issues as the effectiveness of alarms in communicating the desired operator action intent for different fires and their locations; operator time response relative to that used in the timing analysis; proper use of portable equipment, including communication devices and personnel protection; each operator's knowledge on his or her role, particularly if the fire results in different role assignments such as interfacing with the Fire Brigade; and conformance with requirements of the plant fire procedures.

Certainly, most of the above characteristics of the procedures and training, and the bases for these characteristics, will already be covered in existing procedure and training programs. Information regarding the implementation with specific regard to postfire operator manual actions is covered in Section 4.2.9 of this report. The focus here should be on ensuring that those unique aspects, due to the fact this is a postfire response, are indeed addressed.

The importance of this criterion is also consistent with current inspection criteria for fire protection manual actions under both the procedures and the training criteria. Under these criteria, inspectors are to ensure that (1) operators do not have to study procedural guidance at length to operate the equipment in the manner intended, and (2) training on the manual actions and the procedure is adequate and current. This existing practice and the associated expectations support the need for a criterion that addresses procedures and related training needed to successfully perform operator manual actions.

3.2.10 Staffing

The intent of the staffing criterion is to ensure that an adequate number of qualified personnel will be available so that hot shutdown conditions can be achieved and maintained in the event of a fire. Credited personnel may be normally on site, or available through the emergency planning staff augmentation system in time to successfully perform the desired action. Further, individuals that might be needed to perform the operator manual actions should not have collateral duties, such as firefighting, security duties, or control room operation, during the evolution of the fire scenario. In other words, enough trained people, without collateral duties during a fire, should be available to ensure that operator manual actions can be completed as needed.

For instance, an operator should not serve as both a Fire Brigade member and be responsible to perform an operator manual action during a fire at the same time (i.e., he/she should not serve both functions concurrently). The operator could serve as a Fire Brigade member on shift provided another operator had his/her manual action responsibility that same shift. The intent is that an individual who could be called upon to perform operator manual actions should not, for example, also be a member of the Fire Brigade for the same fire, or have other duties that would interfere with his/her ability to perform the operator manual action in a timely manner. Therefore, all operating shift staffing levels should include enough trained personnel to perform any operator manual actions that could arise since any fire could occur at any time.

NUREG-0800, Section 18.0 [Ref. 7], cites NUREG-1764 [Ref. 24] and NUREG-0711 [Ref. 27], which in turn provide NRC staff views with regard to staffing. NUREG-1764 states that "[s]taffing levels should be evaluated based on...[r]equired actions...[t]he physical configuration of the work environment...[a]vailability of personnel considering other activities that may be ongoing and for other possible responsibilities outside the control room...." NUREG-0711 states that "[t]he basis for staffing and qualifications should...address...the knowledge, skills, and abilities needed for personnel tasks...availability of personnel...crew coordination concerns that are identified during the development of training." Also, "validate that the shift staffing, assignment of tasks to crew members, and crew coordination (both within the control room as well as between the control room and local control stations and support centers) is acceptable. This should include validation of nominal shift levels, minimal shift levels, and shift turnover...." In addition, "address...personnel response time and workload...the job requirements that result from the sum of all tasks allocated to each individual both inside and outside the control room...the requirements for coordinated activities between individuals...[and] the interaction with auxiliary operators.... [V]alidate that specific personnel tasks can be accomplished within time and performance criteria, with a high degree of operating crew situation awareness, and with acceptable workload levels that provide a balance between a minimum level of vigilance and operator burden...."

The subject of staffing has also been addressed many times before with regard to NRC's intent in this area. For instance, IN 91-77, "Shift Staffing of Nuclear Power Plants," dated November 26, 1991 [Ref. 41], states that "[t]he number of staff on each shift is expected to be sufficient to accomplish all necessary actions to ensure a safe shutdown of the reactor following an event.... Licensees may wish to carefully review actual staffing needs to ensure that sufficient personnel are available to adequately respond to all events. This is especially relevant to the backshift when staffing levels are usually at a minimum...."

This criterion on staffing is similarly addressed in Section III.L of Appendix R to 10 CFR Part 50 [Ref. 1]. It states, "The number of operating shift personnel, exclusive of Fire Brigade members, required to operate the equipment and systems comprising the means to achieve and maintain the hot standby or hot shutdown conditions shall be on site at all times." The NRC contends that, if the Fire Brigade could be expected to perform actions other than those solely involved with firefighting, the potential exists for interfering with either their firefighting activities or the operator manual action, such that successful performance of one or the other, or both, could be impaired. Although it may seem redundant to require an operator, independent of any firefighting responsibility, to perform an action that could simply be performed by a member of the Fire Brigade, one can conceive of situations where this dual responsibility could be a problem. Hence, operators should be independent of the fire brigade duties and even control room duties since operator manual actions take place outside the control room.

Further, the importance of this criterion is consistent with current inspection criteria for fire protection manual actions under the staffing criterion to determine whether adequate qualified personnel are available to perform the operator manual actions. This existing practice and the associated expectations support the need for a criterion that addresses staffing needs relative to performing operator manual actions.

3.2.11 Demonstrations

This criterion provides a degree of overall assurance that the operator manual actions can be performed in the analyzed time available (i.e., the actions are feasible). This criterion provides a "test" (by at least one randomly selected but established crew) that all feasibility and reliability criteria have been and continue to be met. As a result, the desired operator manual actions are shown to be achievable within the constraints, including the analyzed time available, using the minimum staffing levels, with the expected operable equipment, under the expected environmental conditions (to the extent that they can be reasonably simulated), using the procedures and training provided for the manual actions. The plant staff should not rely upon any operator manual action until it has been demonstrated to be consistent with the analysis.

In addition, this criterion and the criterion to show adequate time available to ensure reliability, which includes showing that extra time exists to account for factors that may not or cannot be covered in the demonstration, complement each other. The demonstration serves as a benchmark against which it can be determined how much extra time is needed to cover the potential influences of the factors not modeled in the demonstration that could delay performance, which more directly addresses the reliability concept. As with training, the demonstration provides the crew with practical experience. All elements of the fire scenario, including, but not limited to, diagnosis of the need for the action, the use of equipment and procedures, adequacy of staffing levels, response to indications, should be integrated into the demonstration to the extent possible to develop this benchmark. In this way, any complexities, such as the number of operator manual actions and their dependence upon one another, and the handling of multiple procedures (emergency operating procedures (EOPs), as well as fire plans and procedures) at the same time, are evaluated and identified for appropriate consideration in determining how much extra time is needed.

Failure to show in a demonstration that the operator manual actions can be accomplished in a manner that is consistent with the analysis (i.e., within the time available to ensure that hot shutdown conditions can be achieved and maintained), indicates that the manual actions are not feasible. In such cases, the plant staff could try modifying the actions (e.g., different access/egress routes, redeployment of critical equipment by placing it at the location where the manual action will be performed vs. carrying it to that location, dividing the activities among a greater number of staff), such that a new demonstration satisfies the analysis. Alternatively, the plant staff could conclude that operator manual actions are not feasible and, therefore, opt for another means to assure that hot shutdown can be achieved and maintained (e.g., passive fire protection features, with fire detection and automatic suppression, as appropriate). Another alternative depends on the nature of the calculations and analysis performed to determine how much time is available. If the calculations and analysis made very conservative assumptions (i.e., they produce a nonmechanistic minimum estimate of the time available rather than a more realistic estimate), then it may be possible to make a strong case that more time would actually be available and that the action is therefore feasible. It may be possible to make such an argument by pointing out how the various assumptions would lead to underestimations of the time available and that if more realistic assumptions were made, adequate time would clearly be available. However, if the effects of the conservative assumptions on the calculated time available are difficult to estimate, additional calculations may be required (see Section 4.2.1 of this report).

Plant staff may determine that operator manual actions are feasible after an initial demonstration has been successfully accomplished and it can be shown that the actions can be performed within the time available. Similarly, if it can be shown that the demonstrated time (or estimated time to complete the action based on the demonstration), along with the extra time needed to account for factors not included in the demonstration, can be enveloped by the estimate of the time available, then it can be argued that the actions may also be performed reliably. If this criterion cannot be met, then as noted above, plant staff could take steps to improve performance of the actions, decide that they cannot be performed reliably, or argue that because of conservative assumptions in the calculations, enough time is available to ensure reliability.

Subsequent demonstrations are likely to be needed for the more complex (see below) operator manual actions, but they may not be necessary for all scenarios by all crews. In some cases, the actions may be straightforward enough that they can be covered through regular training and practice on critical aspects of the operator manual action. In other words, subsequent "full-blown" demonstrations, involving as realistically as possible simulation, may not always be necessary, as long as the operating crews that could be involved in diagnosing or performing the actions receive regular training and practice. As discussed earlier, the training and practice should be done at a frequency consistent with that established in existing training programs on abnormal procedures in compliance with 10 CFR 50.120 [Ref. 39]. This will provide them with experience in performing the operator manual actions.

However, for more complex actions, where, for example, significant coordination might be involved or a sequential set of actions must be executed in a specified order, possibly in different locations or involving multiple individuals, subsequent periodic demonstrations should be carried out to ensure that the actions can continue to be performed reliably. Other general examples that might require periodic demonstrations include situations in which the following three complex conditions exist:

(1) There is a need to decipher numerous indications and alarms.

(2) There may be ambiguity associated with assessing the situation or in executing the task.

(3) The activity requires very sensitive and careful manipulations by the operator, particularly in a time sensitive situation.

Since plant staff will rely on the operator manual actions to ensure the safety of the plant, and because NRC inspectors may ask for periodic demonstrations of various operator manual actions, plant staff should identify the actions that require regular, realistic (as possible) demonstrations and ensure that all crews receive adequate participation in those demonstrations.

Subsequent demonstrations provide valuable training and experience for plant personnel and also serve to verify that plant configuration and conditions (e.g., access, egress) have not changed over time such that the manual actions may no longer be accomplished in accordance with the analyzed time available. If plant staff is unable to successfully complete a subsequent demonstration, they should take corrective action to modify the manual action or the conditions contributing to the inability to successfully complete the demonstration. This agrees with the general concept of corrective action as expressed, for instance, in Criterion XVI of Appendix B to 10 CFR Part 50 [Ref. 37], which requires corrective action measures for conditions adverse to quality. If plant staff is unable to complete a successful demonstration, the staff should opt for another means to ensure that hot shutdown can be achieved and maintained (e.g., passive fire protection features, with fire detection and automatic suppression, as appropriate).

The intent of this criterion is to provide assurance that any crew that might be on duty at the time of a fire can reliably perform the operator manual actions, allowing for variability and uncertainties. It should be sufficient that "an established crew" can illustrate the ability to perform the operator manual actions through a demonstration(s) of the relevant actions. In addition, as discussed above, demonstrations of the more complex actions may become part of periodic operator training. To ensure that all crews (including those receiving training but not performing the demonstration during a particular training cycle) could reliably perform the actions, the criterion of "Showing Adequate Time Available to Ensure Reliability" (i.e., extra time is available (see Section 3.2.2 of this report)) is applied to account for variability that exists among crews as well as for likely shortcomings of the demonstration, as discussed previously. In this way, the demonstration by the established crew would support the position that any of the crews could likewise perform the operator manual actions under a wide range of fire situations.

The use of such demonstrations is supported, for instance, by NUREG-1764 [Ref. 24] and NUREG-0711 [Ref. 27], cited in NUREG-0800, Section 18.0 [Ref. 7]. NUREG-1764 states that "...[a] walkthrough of the human actions under realistic conditions should be performed.... The scenario used should include any complicating factors that are expected to affect the crews['] ability to perform the human actions...." NUREG-0711 states that "...an integrated system design (i.e., hardware, software, and personnel elements) is evaluated using performance-based tests.... Plant personnel should perform operational events using a simulator or other suitable representation of the system to determine its adequacy to support safety operations...."

For this criterion, some fire brigade training expectations from Section III.I of Appendix R to 10 CFR Part 50 [Ref. 1] are useful to apply to operator manual actions. Just as fire brigade

training includes firefighting practice and fire drills, the personnel performing operator manual actions should participate in a similar program of practice and drills for their actions. However, considering these drills in balance with the uncertainties to be addressed in justifying there is adequate time to perform the operator manual action, it may be that the plant personnel decide to perform these demonstrations under near-simulated fire conditions as a means to lessen the uncertainties to be addressed when justifying there is adequate time. Section III.I of Appendix R states that "Practice sessions shall be held for each shift [crew] to provide them with experience in [performing the operator manual actions] under strenuous conditions encountered [during the fire]. These practice sessions should be provided at least once per year for each [operating crew]... [and] performed in the plant so that the [crew] can practice as a team."

It may be impractical for all the operating crews, unlike the plant fire brigades, to perform the operator manual action demonstrations within a 12-month training cycle. As an alternative, feasibility should be shown through demonstrations (of at least the more complex actions) utilizing an established crew at a frequency that is consistent with an existing training program in compliance with 10 CFR 50.120 [Ref. 39] until all the crews eventually demonstrate the more complex actions. However, since as a minimum, only one crew may actually perform the demonstration within a training cycle, additional considerations are needed to provide reasonable assurance that the operator manual actions can be reliably performed (i.e., repeated successfully by any crew at any time). Also, it is likely that the demonstration cannot simulate all the conditions that might be encountered in an actual situation, making it necessary to extrapolate the demonstration to the expected fire conditions. Again, these concerns are addressed via the criterion to show adequate time available to ensure reliability (i.e., extra time is available to account for such conditions). The more simple operator manual actions would be covered through training and practice sessions as prescribed by the plant's training program.

Additionally, the importance of this criterion is consistent with current inspection criteria for fire protection manual actions under the verification and validation criterion to determine whether the manual actions have been verified and validated by simulating the actions using the current procedure. This existing practice and the associated expectations support the need for a criterion that addresses simulating (i.e., demonstrating) the performance of operator manual actions as a means to verify acceptability.

4. TECHNICAL INFORMATION FOR IMPLEMENTING THE FEASIBILITY AND RELIABILITY CRITERIA

4.1 Overview

This section provides technical information for meeting the feasibility and reliability criteria summarized in Section 3 of this report. As discussed in Section 2.3 regarding the scope of this report, this information focus on the *unique* aspects of the hazard involved (fire) and the potentially unique characteristics of subsequent manual actions during the operators' response.

Collectively, to address both the feasibility and reliability of an action, the first two criteria address the following concerns:

(1) analysis of the time available to take the desired manual action considering uncertainties in the estimate of the time available

(2) ensuring there is adequate time considering certain additional uncertainties in the manual action implementation time

Although the approach described below purposely separates (1) and (2) above, it is not intended that plant staff specifically analyze each above concern as separate steps in the analysis process unless the plant staff chooses to address these two criteria in such a two-step fashion. Both criteria can be addressed collectively in one step (and it may be desirable to do so), such as by performing a single-step analysis that can be used to justify both feasibility and reliability, including enveloping possible effects caused by the listed uncertainties.

4.2 Technical Information for Feasibility and Reliability Criteria

4.2.1 Information Regarding the Analysis Showing Adequate Time Available to Perform the Actions to Address Feasibility

For every operator manual action, analyses should show that there is adequate time for the operators to diagnose the need for the actions, travel to action location(s), perform the actions, and confirm the expected response before an undesired consequence occurs, as dictated by the plant staff's determination of the time available to avoid the undesired consequence. An analysis should have the following three elements:

(Element 1) *An estimate of the time available* to perform the manual action based on a calculation that already exists (e.g., a design-basis calculation) or a new calculation, to ensure that hot shutdown can be achieved and maintained. The estimate of the time available should account for unique fire-related uncertainties that could affect that estimate, such as the following examples:

- nature of the fire (e.g., whether the fire is a fast energetic fire, failing equipment quickly, or a slow developing fire with little or no equipment failures for some time)
- reasonable variations in fire detector response times and sensitivities
- typical variations in air flows that could affect the fire and its growth
- specific fire initiation location relative to important targets
- presence (or lack thereof) of temporary but periodic transient combustibles

Note that there are at least two (and perhaps other) ways to account for these uncertainties. One is to perform a conservative analysis (such as using a nonmechanistic assumption that the fire fails everything in a specific location immediately, and yet the detection of the fire triggering operator response is delayed) with a justification that the fire-related uncertainties are enveloped by the conservative analysis. Another is to perform more of a best-estimate analysis such as conducting fire modeling for some fires to estimate equipment damage times, while also accounting for these uncertainties.

(Element 2)__*An estimate of the time to diagnose the need for and implement* the manual action based on input from walkdowns, talkthroughs, judgment, and as substantiated by a demonstration(s). It is preferable that the demonstration replicate, to the extent reasonable, the conditions under which the manual action will have to be performed (see Section 4.2.11 below for information) so that a realistic estimate is made of the total time to diagnose the need for and implement the manual action including (a) the expected diagnosis time (that is, the expected time to confirm the fire, determine its location, and if necessary, determine the need for the action) and (b) the expected execution time (i.e., the expected time to execute the desired action and confirm the desired plant response). The latter might include activities such as the following:

- MCR staff noting the cue(s) of a possible fire
- MCR staff obtaining the correct fire plan and procedures once the fire location is confirmed
- MCR staff informing the plant staff of the fire and calling for fire brigade assembly and actions
- MCR staff alerting and/or communicating with local staff responsible for taking the desired operator manual actions
- MCR staff providing any specific instructions to the responsible local staff for the manual actions
- having the local staff collect any procedures, checking out communications equipment, and obtaining any special tools or personnel protective equipment necessary to perform the actions
- traveling to the necessary locations
- implementing the desired actions noting that some actions may have to be coordinated or done sequentially, that is, cannot start until prior actions are completed and the MCR staff or others are informed, who also may be dealing with the Fire Brigade and handling multiple procedures (EOPs and fire procedures)
- informing the MCR staff and others as necessary that the actions have been successfully completed and the desired effect has been achieved.

(Element 3) *A comparison* of the two times from (1) and (2) (i.e., time available vs. the collective diagnosis and implementation time) *with an accompanying justification/explanation for why there is adequate time available* to complete the action. In the most straightforward case, where it can be shown that the plant staff has calculated a realistic estimate of the time available, it needs only to be shown that the time to diagnose the need for and implement the action (based on the demonstration) is less than the estimated time available. However, if the plant staff has performed an analysis of the time available that produces an estimate closer to the minimum time available (e.g., a nonmechanistic conservative analysis) as opposed to a more realistic

estimate, and this results in the calculated available time being less than the time needed to diagnose the need for and implement the action, then the analysis is not so straightforward. In this case, in order to demonstrate feasibility, justification is needed for why the conservative assumptions included in the analysis of the time available (producing an estimate closer to the minimum time available as opposed to a more realistic estimate) are adequate to "make up" the additional time needed to cover the demonstrated time required. In other words, it should be shown (e.g., provide an explanation) that if the conservatism in calculating the available time was removed, the available time would exceed the time required to diagnose the need for and implement the action.

Another alternative for treating cases where the time available is less than the time needed for the action is to modify the analyses of the time available (eliminating the conservatism and obtaining a more realistic estimate) or to modify the temporal requirements of the actions themselves (e.g., use multiple staff instead of one), until adequate time is shown to be available while still meeting the information in this section.

An example of a timeline analysis approach for addressing the action time relative to available time that address issues that need to be considered is presented in Appendix A to this document. The example is meant to provide information for what should be considered and it is not intended to be a criterion. That is, it is not necessary to show that the example was followed; it is simply an illustration that may be useful for analysts.

4.2.2 Information Regarding the Analysis Showing Adequate Time Available to Ensure Reliability

This criterion addresses the reliability of the operator manual actions. While Section 4.2.1 above addresses the three elements necessary to show the feasibility of an operator manual action, an additional element is necessary in the analysis process to provide sufficient evidence that a manual action can reliably be performed:

(Element 4) A fourth element of the analysis is to *ensure that additional uncertainties in the estimate of the time required to implement the manual action* (listed below) *are accounted for in the analysis* before the final determination is made that adequate time exists for the manual action. Note that, as before, there are at least two ways to account for these additional uncertainties associated with the time required for the manual action. One is to have purposely arrived at a conservative estimate of the time needed to diagnose the need for and implement the manual action (but based generally on the measured demonstration time) with a justification that the *additional uncertainties listed below* are enveloped by the conservative estimate. Another is to specifically account for the additional uncertainties listed below, adding additional time for each applicable uncertainty to the time required for the action as measured from the demonstration.

With respect to the latter option, Appendix B to this report describes an approach that was used to estimate the potential contributions of the various uncertainties to the time required to perform particular actions. However, note that Appendix B describes more than this process. The work described in Appendix B was performed as part of the original rulemaking effort for postfire operator manual actions, which was later discontinued. At that point in time, the potential for including a suggested "time margin"

for operator manual actions was being considered. That is, providing guidance for how much "extra" time should be shown to be available in order to fully demonstrate the reliability of the manual actions. While the results of that exercise suggested that a factor of 2 would serve as a time margin to reasonably envelop all the uncertainties of concern (i.e., 100 percent of the demonstrated time should be shown to be additionally available), the main reason for its inclusion as an appendix to this document is to illustrate the thought process that was used to address the uncertainties associated with the time to perform the action. Analysts may find the discussion useful in estimating the potential impact of the factors creating the uncertainties so as to ensure that there is adequate extra time, but it is not meant to imply that a factor of 2 should always be shown or that analysts should always use such an approach.

The additional uncertainties described below could increase the demonstrated time required to conduct the operator manual actions. They may originate from human performance issues that may not be possible to cover in the demonstration (i.e., under nonfire conditions) and may not have been otherwise already addressed in the analysis. These uncertainties (also covered in Section 3.2.2 of this report) include the following examples:

(a) factors that the plant staff likely may be unable to recreate in the demonstration, or in some cases necessarily anticipate for the real fire situation, that could cause further delay in the time it could take to implement the operator manual action under actual fire conditions (i.e., where the demonstration may likely fall short of actual fire situations), as in the following examples:

- The operators may need to recover from/respond to difficulties such as problems with instruments or other equipment (e.g., locked doors, a stiff handwheel, or an erratic communication device). Such difficulties can and sometimes do occur and represent a possible uncertainty in how long it will take to perform an action. Having extra time makes it less likely that any such difficulties encountered in a real fire situation will prevent performance of the desired manual action in the time available.

- Environmental and other effects might exist that are not easily simulated in the demonstration, such as radiation, for example, the fire could reasonably damage equipment in a way that radiation exposure could be an issue in the location in which the action needs to be taken, causing the need to don personnel protection clothing (which takes extra time), but which may not be included in the demonstration; smoke and toxic gas effects (these are not likely to be actually simulated in the demonstration, but in a real fire where the manual action needs to be taken near the fire location but in a separate room, there may be smoke and gas effects that could slow the implementation time for the action); increased noise levels from the firefighting activities, operation of suppression equipment, or personnel shouting instructions; water on the floor possibly delaying the actions; obstruction from charged fire hoses; heat stress which requires special equipment and precautions; or too many people getting in each others' way. All these may not actually be simulated in a demonstration, but should be considered as possible (and perhaps even likely) when determining the time it may take to perform the manual action in a real situation.

- The demonstration might be limited in its ability to account for (or envelop) all possible fire locations where the actions are needed and for all the different travel paths and distances to where the actions are to be performed. A similar limitation concern is that the location or activities of needed plant personnel when the fire starts could delay their participation in executing the operator manual actions (e.g., they may be in a location that is on the opposite side of the plant off the postulated fire location and/or may need to restore certain equipment before being able to participate). The intent is not to address temporary/infrequent situations but to account for those that are typical and may impact the timing of the action.
- It may not be possible to execute relevant actions during the demonstration because of normal plant status and/or safety considerations while at power (e.g., operators cannot actually operate the valve using the handwheel, but can only "talk through" doing so).

(b) factors involving typical and expected variability between individuals and crews leading to variations in operator performance (i.e., human-centered factors), such as the following examples (as noted earlier, given the likely experience and training of plant personnel performing the actions, it need not be assumed that these characteristics would lead to major delays in completing the actions, but their potential effects should be considered in the specific fire-related context of the actions being performed, to confirm this assumption):

- physical size and strength differences that may be important for performing the actions
- cognitive differences (e.g., memory ability, analytic skills)
- different emotional responses to the fire/smoke
- different responses to wearing SCBAs to accomplish a task (i.e., some people may be more uncomfortable than others with a mask over their faces, thus affecting action times)
- differences in individual sensitivities to "real-time" pressure
- differences in team characteristics and dynamics

Only when a comparison similar to that discussed under item 3 in Section 4.2.1 above is done (i.e., a comparison of time available to the collective diagnosis and implementation time), but which accounts for these additional uncertainties and inevitable variability in the time required for the manual action, would this analysis be complete.

4.2.3 Information Regarding Environmental Factors

Environmental conditions encountered by operators while traveling to and from action-related areas, accessing the areas, and performing the operator manual actions should be shown to be consistent with established human factor considerations, including the following:

- Emergency lighting should be provided as required in Section III.J of Appendix R to 10 CFR Part 50 [Ref. 1], or by the plant's approved fire protection program.
- Radiation should not exceed the limits of 10 CFR 20.1201 [Ref. 20].
- Temperature and humidity conditions should not prevent successful performance of the operator manual actions or jeopardize the operator's health and safety. Heat stress analysis may be appropriate for an environment expected to significantly tax the individual in this manner to ensure the desired action can be performed successfully and without harm to the individual.
- Smoke and toxic gases from the fire should not prevent accessing the necessary equipment, hinder successful performance of the operator manual actions or jeopardize the health and safety of the operator. Plant staff should account for expected smoke and toxic gas levels to ensure that they will not affect performance where it is expected such conditions will exist.

If habitable environmental conditions are present when traveling to and from the location(s) where the relevant activities need to take place, as well as at the location(s) itself, the criterion will generally be easily met. However, several other issues also should be considered:

- The donning and wearing of special personnel protective gear such as SCBAs, firefighting turnout gear, gloves, or other protective items to accomplish the operator manual actions in the fire-impacted environment can slow personnel down because of limited visibility or loss of manual dexterity and may hinder their ability to communicate effectively. Reliable communication may be essential if multiple personnel are involved. As discussed in Section 4.2.11 below, if such special gear might be needed in order to successfully complete the operator manual actions, then it is desirable that the gear should be used during the demonstration to substantiate its effectiveness and its impact on the time to complete the actions. While it is possible to perform the desired actions by meeting in "clear" areas to communicate or by going to clear areas where communication devices are located, at a minimum, time delays during the response should be considered. It is desirable that such activities be included in the demonstration if they are going to be used.
- Plant staff should make certain that any special equipment related to environmental conditions, such as protective clothing or flashlights that might be needed for activities in especially dark areas, are readily available and their location constant and known to those who need to use the equipment. Access to this equipment should be unimpeded so that it will not delay the operator manual actions, and this equipment needs to be in working order (functional). These types of activities should be included as part of the demonstration and included in the time to complete the actions.

4.2.4 Information Regarding Equipment Functionality and Accessibility

This criterion addresses the need to ensure that the equipment that is necessary to implement an operator manual action to achieve and maintain postfire hot shutdown is accessible, available, and not damaged or otherwise adversely affected by the fire and its effects. The criterion is meant to ensure that the desired operator manual actions can be successfully performed using that equipment in the manner required by the operator manual action per the applicable procedures and training.

In crediting the functionality of the equipment, the following should be considered:

- Unique fire effects (such as heat, smoke, water, combustible products), and spurious operation that may render the component inoperable by manual or remote manipulation.
- No credit for operator manual actions and the related equipment should be taken involving the use or manipulation of equipment located where it could be exposed to the fire and its effects. If crediting the use of equipment potentially exposed to the fire and its effects is necessary and this should occur only in rare and exceptional circumstances (e.g., using fire-unaffected equipment in an area well after the fire is extinguished), the plant staff should provide justification as to the continued functionality of the component or components for the intended manipulation.[7]
- All the needs of the equipment are to be met for the equipment to be "functionally available." For instance, if the operator manual actions involve the use of a switch and subsequent control signal to a component, the supporting electrical power and signals and associated cabling need to be available. Further, if the equipment's functionality relies on certain support systems (e.g., cooling, ventilation, power, air from a nearby tank) to be manipulated and continue to function (if needed) in the desired manner, those equipment support functions need to also be in working condition and available.

Knowledgeable personnel are to have adequate accessibility to all the necessary equipment and other aids (e.g., diagnostic indications, components to be manipulated, protective clothing, special tools, keys, procedures, communication equipment), and be able to readily locate the equipment and use or otherwise manipulate the equipment in the desired manner per the procedures and training under the anticipated range of fire-related conditions. Considerations in meeting the adequate accessibility criterion should include the following:

- the range of conceivable environmental conditions (see the environmental considerations criterion) under which the actions will be performed, especially radiation and fire-related conditions such as abnormal temperature, radiant energy, and smoke
- physical access or manipulation constraints, especially for locations likely to be congested or where routine operations do not occur or for manipulations not normally performed

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[7] In doing so, it is preferable that a different exemption request format be used, such as a risk-informed/performance-based exemption via Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, issued November 2002) [Ref. 42], or one following National Fire Protection Association (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants," [Ref. 43], so as to be able to consider the specific fire scenario and the related conditions.

- the possibility that preferred access/egress routes may become inaccessible and alternate routes may need to be used
- the possibility that security doors or similar restraints could be physically or electrically affected by the fire

Consistent with information for equipment functionality, no credit for operator manual actions should generally be taken at locations exposed to the fire and its effects.

An example of the type of functionality issue that should be considered was discussed in Section 3.2.4 of this report with regard to IN 92-18 [Ref. 30]. The information notice focused on MOV functionality due to possible fire damage to control cables. The bypassing of thermal overload protection devices (discussed in Regulatory Guide 1.106 [Ref. 31]) could jeopardize completion of the safety function or degradation of other safety systems due to sustained abnormal circuit currents that can arise from fire-induced "hot shorts." Even if these overload protection devices are not bypassed, hot shorts can cause loss of power to MOVs by tripping the devices. If equipment (including cabling and other support needs such as power and cooling) that could be affected by the fire or its subsequent effects are to be used for operator manual actions, the plant staff should determine that the functionality and performance of that equipment will not be adversely affected so that the function can be successfully achieved by the manual actions.

4.2.5 Information Regarding Available Indications

Diagnostic indicating instrumentation should be among the equipment identified as needed, to the extent it is required to (1) enable the operators to determine which manual actions are appropriate for the fire scenario, (2) tell the personnel how to properly perform the manual actions, and (3) provide feedback to the operators, if not already directly observable, to verify that the manual actions have had their expected results. The available indications should include those indications necessary to detect and diagnose the location of the fire to the extent this information is needed to meet (1) through (3) above. As part of the necessary equipment, indicating instruments should be functional and accessible as discussed earlier, especially in light of the possible harsher than normal conditions in which the indications may need to operate. In addition the following considerations should be addressed:

- The available indications should be all that are needed, either in the MCR or in local areas, to meet, as necessary, (1) through (3) above, including indicators such as annunciators, indicating lights, pressure gauges, flow indicators, and local valve position indicators.
- A review to identify the needed indications should include situations where there are no alarms for potential spurious equipment operations nor any other compelling signal that the equipment status has changed and is detrimental to the safety functions (e.g., a valve shutting that changes the indication of an open lit light to a closed lit light). In such cases, the operator is more likely to miss the change in status and, therefore, not respond to it. To the extent feasible, compensatory measures should be provided. For example, a local operator observes the equipment (part of the staffing requirement), or there are warnings in the procedure to watch for and frequently check specifically identified equipment status relevant to the fire.

The available indications, where necessary, should be sufficiently redundant or diverse such that the operators should be able to detect potential faulty indications as a result of the fire (such as may be caused by failure or spurious operation due to the fire or due to loss of power caused by the fire) and can determine the true plant status by viewing other indications or by getting other independent local operators to verify the suspect indication. Such redundancy and/or diversity considerations should consider where multiple indications could be affected by one spurious fault or failure, such as the loss of a common power supply or a cascading circuit (e.g., a faulty wide range reactor coolant system pressure signal will affect not only the pressure indication but also the subcooling indication because the signal is used to calculate subcooling). Such erroneous indications could be particularly troublesome since, taken together, they may appear normal.

4.2.6 Information Regarding Communications

Adequate communications capability should be illustrated for operator manual actions that need to be coordinated with other plant operations and personnel. Beyond the use of face-to-face interactions, any communications capability necessary to successfully perform the operator manual action (e.g., need to use two-way radios, internal phone system) should be routinely and readily available for all personnel involved in the actions and should be protected from the effects of a postulated fire. It should be noted that the unpredictability of fires can force plant staff to deviate from planned activities (hence, the need for effective, and in some cases, constant communications). In addition, communications permit the performance of sequential operator manual actions (where one action must be completed before another can be started) and provide verification that procedural steps have been accomplished, especially those that must be conducted at remote locations. More information on communications follows and should be considered to the extent applicable for the communication form that is to be used (e.g., face-to-face interaction, use of electronic devices) to implement the operator manual action:

- For the actions of interest, it should be shown that a potential fire will not damage or disable communications equipment if that communications equipment is needed to successfully perform the operator manual action, and that the ability of personnel to successfully use that equipment, given other factors introduced by the fire (e.g., the need to wear protective clothing), will not be adversely affected.
- There should be confirmation that the desired means of communication will work in particularly noisy environments (best done by testing under the noisy condition, if feasible).
- Personnel should have substantial training on activities that involve coordination and communication, including how to clearly state important information. Further, if the means of communication must be set up or otherwise made available, the time to do so should be factored in the time to implement the desired actions.
- As noted in other sections of this document, the plant staff should have shown the ability to communicate while wearing protective gear such as SCBAs, preferably during the demonstration, if that form of communication is likely to be needed to perform the desired operator manual action.

4.2.7 Information Regarding Portable Equipment

Portable equipment may also be needed for some operator manual actions. Portable equipment, especially unique or special tools (such as keys to open locked areas or manipulate locked controls, flashlights, ladders to reach high locations, torque devices to turn valve handwheels, and electrical breaker rackout tools), can be essential to access and manipulate SSCs in accomplishing operator manual actions. Therefore, portable equipment should also be functional and accessible to the extent it is needed to successfully implement the operator manual action. Crediting the use of portable equipment should include the following considerations:

- The portable equipment should be readily available and its location constant and known to those who need to use the equipment. Access to this equipment should be unimpeded so that it will not delay the operator manual actions, and this equipment needs to be in working order (functional).
- The portable equipment should be controlled and it should be routinely verified that the portable equipment is indeed located where it is supposed to be and has not been misplaced or otherwise moved.
- Personnel should be trained to use the special tools and equipment in the planned application.
- If the use of the portable equipment may slow down action implementation, the delay should be considered in the time estimated (and preferably included in the demonstration) to perform the desired actions.

4.2.8 Information Regarding Personnel Protection Equipment

The necessary equipment also includes personnel safety equipment as it is needed to successfully perform the manual actions and prevent harm to personnel. Such equipment could include, for instance, protective clothing, gloves, and SCBAs. Therefore this component also needs to be functional and accessible to the extent it is needed to successfully implement the operator manual action. Considerations for crediting the use of personnel safety equipment should include the following:

- Consideration needs to be given not only to the locations for the operator manual actions, but also to access and egress paths to and from the locations, considering the fire and its effects.
- The personnel safety equipment should be readily available so that its locations are known by those who need to use it, and there will be no delay in obtaining and donning the protective equipment.
- Personnel should be trained to use the protective equipment in the planned application.
- If the use of the protective equipment may slow down the action because of limited visibility, loss of manual dexterity, difficulty in communicating, or other factors, the delay should be considered in the time estimated (and preferably included in the demonstration) to implement the desired actions. Use of SCBAs, including any credit for communication while they are being worn, should only be credited if their capability has been demonstrated by trained personnel. While it may still be possible to perform

the desired actions by meeting in clear areas to communicate or by going to clear areas where communication devices are located, at a minimum, time delays during the response should be considered and it is desirable that these activities be included in the demonstration if life support equipment is going to be used.

4.2.9 Information Regarding Procedures and Training

4.2.9.1 Procedures

To help ensure that operator manual actions are performed successfully, procedural guidance for the actions should be readily available, easily accessible, and contained in a maintained and controlled procedure. Operators should generally not rely on having adequate time to locate, review, and implement seldom-used plant procedures to know when and how to operate plant equipment during a fire event. The procedures should accomplish the following:

- Assist the operators (usually in conjunction with indications) in correctly diagnosing the type of plant event that the fire may trigger, thereby permitting them to select the appropriate operator manual actions.
- Direct the operators as to which manual actions are appropriate to place and maintain the plant in a stable, hot shutdown condition for a fire in a given area.
- Minimize the potential confusion that can arise from fire-induced conflicting signals, including spurious actuations, thereby minimizing the likelihood of personnel error when personnel are performing the operator manual actions.

Existing procedural programs will already cover most aspects of ensuring the fire procedures are adequate (e.g., level of detail, ensuring no conflicts). Given the variety of conditions that can occur during a fire, the procedures should also alert personnel to any potentially hazardous conditions that might be generated by fires in particular locations (e.g., expected hazards such as water on the floor caused by firefighting activities in nearby areas). Furthermore, during the development of the procedures, the plant staff should identify any potential "informal rules" that might exist in the plant or biases that might be held by plant personnel about fire conditions and make sure they are addressed in the procedures and during training, if appropriate (e.g., conditions under which personnel should be concerned about interactions between water and electricity).

Finally, there are special considerations for the two general types of operator manual actions in response to fire:

- In the case of preventive actions (i.e., actions that the plant staff expects to take on the basis of the occurrence of a particular fire, without needing further diagnosis, in order to mitigate the potential effects of possible spurious actuations or other fire-related failures so as to ensure that hot shutdown can be reached and maintained), the procedures should be written to cover the possibility that the fire effects occur before the preventive actions are completed. For such cases, the procedures should direct the operators to verify equipment state and position and manually align the equipment as necessary to reach hot shutdown. For these procedures, it is important that operators have a step which directs entry into these preventive actions (e.g., upon

verification of a fire in the fire area) to increase the chances that the steps are performed prior to the occurrence of fire damage.

- For reactive actions (that is, actions taken by plant staff during a fire in response to an undesired change in plant status when the staff must diagnose the need for the actions), relevant procedures should clearly describe the indications which prompt initiation of the actions. If redundant cues are available, they should also be addressed in the procedure to aid the operators when the fire causes spurious effects. Crews should be aware that the cues for such actions can, in principle, occur at any time during a fire. If necessary due to timing considerations, such actions may need to be made "continuous action statements" in the fire procedures.

4.2.9.2 Training

Since plant procedures need to include operator manual actions credited to achieve and maintain hot shutdown, each operator that might be required to perform the actions to reach hot shutdown needs to be appropriately trained on those procedures. Training on the fire procedures should accomplish three goals:

(1) Establish familiarity with the fire procedures, any equipment/controls needing manipulation to perform the desired operator manual actions, and the potential conditions in an actual fire event, including the necessary indications and human-machine interfaces.

(2) Provide the level of knowledge and understanding necessary to prepare the personnel performing the operator manual actions to handle departures from the expected sequence of events if the need arises.

(3) Give the personnel the opportunity to practice their response without exposure to adverse conditions, thereby enhancing confidence that they can reliably perform their duties in an actual fire event.

As with the procedures, most of the training needs for performing the desired operator manual actions will already be addressed by an existing training program once the manual actions are included in the training program (e.g., trainer qualifications, use of practice and classroom activities, ensuring training is current).

In addition, there may be some actions that need to be practiced under conditions that are as realistic as possible, on a regular basis, by all crews (i.e., the actions need to be demonstrated on a routine basis to ensure that they can be performed reliably). For these operator manual actions, actual demonstrations of the actions under conditions that closely approximate actual fire situations should be part of the training program (see Section 4.2.11 below for more on demonstrations).

There are several areas in which special (but not unusual) training will be needed to support operators' ability to complete the manual actions in postfire situations:

- All plant personnel who may need to wear protective clothing to perform the actions should receive training in donning the clothing, traveling to the action locations while wearing the protective clothing, and conducting the relevant actions while wearing the protective clothing.

- Personnel should train on the use of SCBAs and should practice all aspects of the relevant operator manual actions, including communication, while wearing the SCBAs, if they are likely to be required to wear them in an actual fire.
- If communications among personnel are necessary to accomplish the actions, the communications should be part of the training on the actions and should be practiced under conditions that are as realistic as possible for the expected conditions. The personnel should also be well trained in the range of communication equipment that might be necessary. In addition, plant staff should provide guidance and practice on how to best state the relevant information to be understood.
- Along similar lines, if personnel must work as a team to accomplish certain overall goals, such as when having to perform multiple actions in a certain sequence from various locations, they should be given guidance on how to perform effectively as a team to achieve the particular actions and they should practice the actions as a team. Since it is unlikely that "fixed" teams will always be available for specific actions, individuals should have the opportunity to train on the range of activities to achieve the actions.
- The training should include any technical knowledge regarding fires that will be important to ensure adequate operator response to the fire scenario.

With a frequency consistent with that established by the plant staff in compliance with 10 CFR 50.120 [Ref. 39], the plant staff should conduct demonstrations of at least the more complex actions (see Section 4.2.11 of this report for more on this subject) with established crews of operators, showing that the manual actions needed to achieve and maintain the plant in a hot shutdown condition can be accomplished under conditions closely resembling those anticipated in a real fire event.

4.2.10 Information Regarding the Staffing Criterion

To meet the staffing criterion, it is important that the persons involved in performing the operator manual actions be numerous enough and sufficiently qualified to collectively perform the desired actions to achieve and maintain hot shutdown in the event of a fire. Additionally, the following considerations should be addressed:

- Adequate numbers of qualified personnel should be available within the timeframe credited in the analysis for performing the various operator manual actions. Credited personnel may be normally on site, or available through the emergency planning staff augmentation system, as long as the necessary timing of the action(s) can be met.
- Individuals that might be needed to perform the operator manual actions should not have collateral duties, such as firefighting or control room operation, during the evolution of the fire scenario. For instance, an operator should not serve as both a Fire Brigade member and be responsible to perform an operator manual action during a fire at the same time (i.e., he/she should not serve both functions concurrently). The operator could serve as a Fire Brigade member on shift provided another operator had his/her manual action responsibility on that same shift. The intent is that an individual who could be called upon to perform operator manual actions should not, for example, also be a member of the Fire Brigade for the same fire.

Appropriate staffing largely depends on the activities that need to be performed in accordance with the timing and action related analyses discussed earlier. The following should also be considered in evaluating the staffing for the performance of operator manual actions:

- The number of persons should be sufficient to meet the workload assumed in analyses of the time available and the time needed to complete the operator manual action and, as shown under the demonstration criterion, successfully achieve and maintain hot shutdown. Decisions about staffing levels should take into account all operator manual actions that are expected in a particular fire scenario. Since different scenarios may involve different sets of operator manual actions, staffing levels should meet that required for any scenario in terms of the number of staff needed to meet the timing requirements.
- The staff should be trained and qualified in their assigned duties for performing the operator manual actions. This should be performed per the plant's normal training practices and include special considerations given that the desired actions will need to be carried out during a fire (see the procedure and training criterion). Special considerations may include verification of the availability and reliability of instrumentation and equipment, assessing damage to equipment, deenergizing critical equipment to protect it, reenergizing buses, manually manipulating equipment that normally is automatically controlled, implementing fire-specific procedures (including important plant site and offsite notifications), assisting or supporting firefighting activities, and potentially dealing with injuries to plant personnel.
- No single individual should have task assignments nor a task load that results in excessive physical or mental stresses, nor coincident tasks that challenge each person's ability to perform the desired actions in the analyzed times under the range of anticipated conditions. Plant staff should be able to successfully defend their assumptions regarding the ability of the relevant staff to perform under the expected conditions.

4.2.11 Information Regarding How to Perform a Demonstration

This criterion for operator manual actions in response to fire addresses the fact that each action needs to be demonstrated at least once (by one randomly selected but established crew) to show that the feasibility and reliability criteria have been and continue to be met. As a result, the desired operator manual actions should be shown to be accomplishable within the constraints, including the analyzed time available, using the minimum staffing levels, with the expected operable equipment, under the expected environmental conditions (to the extent reasonable), using the procedures and training provided for the manual actions. The plant staff should not rely upon any operator manual action until it has been demonstrated to be consistent with the analysis.

While it is easiest to conceptually imagine each action being individually demonstrated for different fire scenarios, it is acknowledged that some actions and the fire scenario contexts may have characteristics that are very similar (e.g., the actions themselves are similar, timing related to when the actions have to be performed and how long it would take to implement the actions are similar, locations for the actions are not vastly different as to significantly affect travel time to the locations, similar environments exist for the locations for the actions). In such cases, with justification, a demonstration of an action for a given scenario could be argued to bound or

otherwise represent other similar actions in similar circumstances. Hence, one demonstration may be sufficient to credit other similar actions under similar situations.

In addition, subsequent demonstrations should be performed for the more complex (see below) operator manual actions, but they may not be necessary for all scenarios by all crews. In some cases, the actions may be straightforward enough that they can be covered through regular training and practice on critical aspects of the operator manual action. In other words, subsequent "full-blown" demonstrations, involving as realistically as possible simulation, may not always be necessary, as long as the operating crews that could be involved in diagnosing or performing the actions receive regular training and practice. As discussed earlier, the training and practice should be done at a frequency consistent with that established by the plant staff for their plant training programs on abnormal procedures in compliance with 10 CFR 50.120 [Ref.39]. This will provide them with experience in performing the operator manual actions.

However, for more complex actions, where, for example, significant coordination might be involved or a sequential set of actions has to be executed in a specified order, possibly in different locations or involving multiple individuals, subsequent periodic demonstrations should be carried out to ensure that the actions can continue to be performed reliably. Other examples that might require periodic demonstrations include situations involving the following complex conditions:

- There is a need to decipher numerous indications and alarms.
- There may be ambiguity associated with assessing the situation or in executing the task.
- The activity requires very sensitive and careful manipulations by the operator, particularly if under time stress.

Since plant staff will rely on the operator manual actions to ensure the safety of the plant, and because NRC inspectors may observe and assess periodic demonstrations of various operator manual actions, plant staff will need to identify the actions that require regular, realistic demonstrations and ensure that all crews receive adequate participation in those demonstrations.

An important purpose of demonstrating the actions and showing that they can be completed in the time available, is to document the feasibility of the actions. However, for the demonstration to be robust, it is desirable that the demonstration be conducted under conditions that are as realistic as possible. Of course, it is clear that, in spite of plant staff's best efforts, there may be conditions that are very difficult, if not impossible, to simulate. This is one of the reasons it is necessary to show that additional time is available beyond that required based on the demonstration (i.e., to provide a way to account for potential shortcomings in the ability to adequately simulate the actual plant conditions during the demonstration). That is, a tradeoff exists between the extent to which the demonstration is realistic, and the uncertainties to be addressed as part of justifying there is adequate time to perform the operator manual action. For instance, more realistic demonstrations translate into less uncertainty with regard to justifying that there is adequate time.

This section provides information on what should be considered and how to ensure that the demonstration is appropriate. One of the first steps in performing a demonstration is to ensure that all relevant aspects of the other feasibility and reliability criteria are met, and that

the important characteristics of those criteria are included to the extent possible. In other words, the demonstration should include all aspects that could influence the outcome of the actions, if it is reasonable to do so. Things to consider under each of the criteria are discussed below.

Before proceeding, it should be noted that, to the extent reasonable, the entire fire-induced accident scenario should be simulated for the demonstration, including all the expected MCR activities, if the response to the fire is expected to credit operator manual actions. More details on the nature of the simulation are given below. While it is desirable that any demonstration simulates the fire conditions to the extent reasonable, under all circumstances, the demonstration should be done by taking into consideration the ability to replicate expected fire conditions safely for personnel, and without jeopardizing the safe operation of the plant. All actions associated with detecting and diagnosing the presence of the fire and diagnosing the need for and executing the relevant manual actions should be timed during the demonstration. Obviously, this information will be important in determining whether there will be enough time available to perform the actions.

4.2.11.1 Environment

Once it is determined (per the information in this report) that the relevant actions are possible under the environmental conditions expected to be present in the areas which operators will have to access to complete the actions, as well as in the locations of the actions, it is desirable that those conditions be simulated to the extent reasonable (noting the safety considerations cited above). For example, the following conditions could be simulated in all relevant areas, including areas through which the operators may have to travel:

- the lighting levels expected to be present during the actual fire to the extent feasible and safe (if dangerous to simulate, should be considered in determining how much extra time is needed)
- if the environmental conditions are assumed to involve the use of SCBAs at any time in the scenario, then the donning and wearing of these during those periods
- if protective clothing will be needed at any time, then the donning and wearing of this during those periods
- if SCBAs may be needed, then any communications anticipated during those periods when the SCBAs are worn (assumes personnel who use SCBAs receive training and are qualified in their use)
- the noise levels expected to be present during the fire scenario, if feasible

4.2.11.2 Equipment Functionality and Accessibility

Accessibility to the relevant systems and equipment is necessary to enable the personnel to perform the operator manual actions. To the extent possible, the personnel participating in the demonstration should carry out the actions if the actions can be done without affecting the safety of the plant (e.g., manually open a valve with the handwheel). If the demands of the task and the time to complete the actions must be based on the judgments of plant personnel, then a process should be used to help ensure that the estimates are reasonable (e.g., get multiple independent judgments). A preferred approach is to obtain estimates

of the time to execute specific actions when safety is not a concern (e.g., during shutdown or when the system is out of service for some reason).

In addition, if the plant history indicates that certain equipment tends to have persistent types of problems (e.g., a tendency for valve hand wheels to be stiff), then those conditions should be assumed for the demonstration and not preconditioned solely for the demonstration.

4.2.11.3 Available Indications and Main Control Room Response

In conducting the demonstration the actual effects of the fire conditions should be simulated, to the extent possible, in the plant training simulator and the operators should diagnose the need for the relevant actions based on the expected pattern of indications. In other words, the presence of the cues needed to detect the fire should be simulated, and the crew should have to respond accordingly. The MCR response to the scenario should be the same as during an actual fire. The MCR crew should enter the relevant procedures based on the expected indications and take the necessary steps to respond to the fire and reach hot shutdown. The parameters indicating the need for the operator manual actions in response to the fire should also be simulated, and the crew should have to summon the staff necessary for the manual actions, retrieve the relevant procedures, provide the necessary guidance, and interact with the individuals as necessary while they complete the actions for the demonstration. In addition, the personnel executing the actions should have to check relevant indications of successful completion of the actions and verify completion. These indications should be accurately simulated to the extent possible.

All aspects of the scenario associated with diagnosis and the execution of the actions should be timed. This will provide information relevant to determining the time to diagnose the need for the actions and the time needed to implement the actions. If any aspects of the scenario cannot be simulated, their potential impact on the time should be estimated.

4.2.11.4 Communications

The communications necessary to complete the operator manual actions should be part of the demonstration. This should include communications necessary from the detection of the fire through completion of the actions. Examples of conditions that should be included in the demonstration include the following:

- If it cannot always be assumed that the personnel expected to perform the actions will be in the control room at the time they will be needed, then consideration for where the personnel might be with respect to being able to communicate with the control room should be included in the demonstration. If personnel might be in areas where someone would have to be sent to get them, then this activity should be simulated.
- If personnel must be able to communicate with each other and with the control room, then those communications should be part of the demonstration.

4.2.11.5 Portable Equipment

Any portable equipment that will be needed to conduct the operator manual actions during a real fire should also be accessed and used to the extent reasonable during the demonstration. Portable equipment includes unique or special tools, such as keys to open locked areas or manipulate locked controls, flashlights, ladders to reach high places, torque devices to turn valve handwheels, and electrical breaker rackout tools. Such equipment should be located where it would be expected to be located during a real fire. The equipment should not be gathered together and made easily accessible just for purposes of the demonstration (i.e., no preconditioning).

4.2.11.6 Personnel Protection Equipment

Similar to the portable equipment noted above, any personnel protection equipment such as protective clothing, gloves, and SCBAs should be located, accessed, and donned as during an actual fire.

4.2.11.7 Procedures and Training

All activities associated with the use of procedures should be addressed in the demonstration, including the following:

- detection of the entry conditions for the procedures
- retrieval of the procedures
- the potential need for multiple copies
- usability of the procedures under the expected condition (e.g., lighting levels, a place to put them during their execution if they must be closely followed)

In addition, while the selection of a crew for the demonstration should be random, it should be ensured that there has been no preconditioning such as limiting the selection to only those crews most recently trained.

4.2.11.8 Staffing

Staff who will have duties associated with successful completion of the actions (including diagnosis and execution of the actions) should participate. Staffing issues such as the following should be considered in the demonstration:

- If personnel will have to be summoned from outside the MCR, how long it will take them to get to the control room should be assessed as part of the demonstration considering the likely starting locations for the personnel based on where these persons are typically located. Plant staff should consider the potential for the personnel to be in remote locations from which it is difficult to egress and that the personnel may have to complete some actions before they can leave an area if this is the typical situation for some staff members. It would then be preferred that these considerations be included in the demonstration.
- If the actions will involve multiple staff in certain sequences, then these activities, their coordination, and their associated communication aspects should be included.

- If the MCR crew is likely to be directing and coordinating multiple teams involved in executing manual actions, these activities should be simulated. Furthermore, if the individuals in the MCR coordinating these activities will have other significant responsibilities, those responsibilities should also be simulated.

4.2.11.9 Other Aspects Important to the Demonstration

There are several other important issues or aspects that plant staff should consider in conducting an appropriate demonstration:

- If the operator manual actions being examined are preventive actions and it is reasonable that the fire could negatively affect the relevant equipment before the preventive actions are completed, then the participating personnel may need to verify equipment state and position and manually align the equipment as necessary (i.e., take an additional reactive action to restore the equipment to the desired state). Thus, the implementation time for the actions should include the time it would take plant personnel to complete the actions necessary to manually place the affected equipment in its desired state.
- If the operator manual actions being examined are reactive actions, then the plant staff should be aware that the cues for the need for such actions and the associated effects could, at least in principle, occur at any time after the fire starts. Thus, the effects could occur early, during the diagnosis stage of the scenario, or sometime after that. For purposes of the demonstration, plant staff should estimate when the worst-case timing for the occurrence of the spurious fire effects on the relevant equipment would be with respect to the level of activity in the MCR and the plant in general. That is, the equipment should be assumed to be affected at that time which leaves the shortest available (allowable) time to perform the desired actions. This could be based on a nonmechanistic conservative assumption or, for instance, based on some level of best-estimate fire modeling such as accounting for the location of the fire source(s) and fire size(s) relative to relevant equipment so as to determine when the equipment could be damaged. Other factors that might be considered in determining when to assume that the equipment is affected by the fire might include potential interactions with and effects on other equipment.
- If the fire or other factors could affect where personnel have to travel (e.g., what routes they have to take) and where they have to enter and exit various rooms, then this should be considered in the modeling for the demonstration and determining the travel time.
- If the conditions that could be generated by the fire have the potential to vary significantly, this should be accounted for when deciding how to model the scenario(s) for purposes of the demonstration.
- If smoke could significantly affect visibility, the action should generally not be credited.

In general, plant staff should strive to make the demonstrations as realistic as possible and make conservative assumptions as necessary. If this is done and the above information is followed, then the resulting demonstrations, in conjunction with determining adequate time considering certain uncertainties, should achieve the goal of crediting only feasible and reliable operator manual actions.

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APPENDIX A

GUIDELINES FOR USING TIMELINES TO DEMONSTRATE SUFFICIENT TIME TO PERFORM THE ACTIONS

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APPENDIX A
GUIDELINES FOR USING TIMELINES TO DEMONSTRATE SUFFICIENT TIME TO PERFORM THE ACTIONS

This appendix provides information for using timelines to investigate and illustrate that sufficient time exists to perform the postfire operator manual actions.[1] It is an additional tool to support the assessment of operator manual actions to be used by analysts if desired. The appendix addresses issues involved in making such an assessment, such as the impact of multiple, serial, or parallel actions and differing considerations for preventive and reactive actions. In conjunction with the information in the body of this report, the goal is to illustrate that there is adequate time available to perform all relevant actions and account for additional uncertainties that might not be covered by the demonstration of the action. The approach includes the use of timelines to show that there is sufficient time to diagnose the need for the actions, travel to action locations, perform the actions, and confirm the expected response. The timeline approach should have the following elements, as illustrated in Figure A-1:

(1) The time of fire detection (T_0), which begins the timeline and represents the first indication that a fire may exist, or at least suspect that a fire has begun. Detection may be via alarms, indicators, an observation from a roving operator, or other means.

(2) An expected diagnosis time (that is, the expected time to confirm the fire and determine its location). This time is obtained from the demonstration (see the demonstration criterion discussion later) and T_1, the end of the diagnosis time, is to be marked on the timeline.

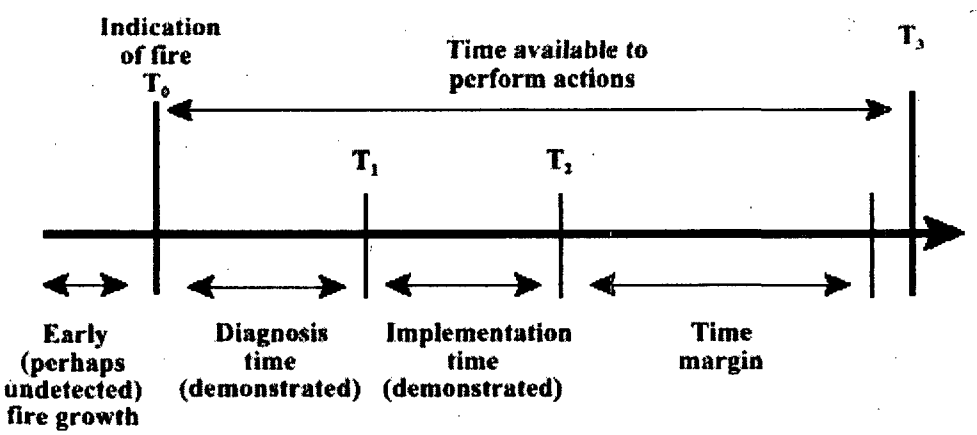

Figure A-1. A timeline

[1] "Operator manual actions" are defined in the Glossary of this report. For this report, they do not include the action(s) associated with abandoning the main control room (MCR) in the case of a fire.

(3) An implementation time that is the expected time to implement the desired action or actions. This time is obtained from the demonstration (see the demonstration criterion) and includes such activities as MCR staff obtaining the correct fire plan and procedures once the fire location is confirmed; informing the plant staff of the fire; calling for fire brigade assembly and actions; calling for and/or communicating with local staff responsible for taking the desired local manual actions; providing instructions to the responsible local staff for the manual actions; having the local staff collect any procedures, checking out communications equipment, and obtaining any special tools or clothing necessary to perform the actions; traveling to the necessary locations; implementing the desired actions (some actions may have to be done sequentially (i.e., cannot start until prior actions are completed)) and communicating with the MCR staff or others as necessary, who in turn may be simultaneously dealing with the Fire Brigade, handling, for example, multiple procedures (emergency operating procedures and fire procedures); and telling the MCR staff and others as necessary that the actions have been completed and the expected effect has been achieved. The implementation time ends at T_2, as shown in the figure. Hence, the total time to be obtained from the demonstration begins at T_0 and ends at T_2.

Note that after the initial diagnosis time, subsequent actions may or may not include subsequent diagnosis times. For instance, in the case of performing proceduralized preventive actions, no other diagnosis time may be needed for some actions. Alternatively, if the desired action is a reactive action in the sense that it is taken only after diagnosis of an undesired equipment status (e.g., loss of feedwater after a valve spuriously closes), then that diagnosis time needs to be included (e.g., deciding what action to take and by whom) as illustrated in Figure A-2. The time available (T_3, the time available to ensure hot shutdown can be achieved and maintained) to complete these reactive actions will need to be measured from the worst-case point at which the equipment could be affected. In other words, since spurious effects caused by the fire could, in principle, occur at any time, analysts would need to determine the point at which the least amount of time would be available to complete the reactive action and successfully restore the availability of the equipment. This could be based on a nonmechanistic conservative assumption or, for instance, based on some level of fire modeling such as accounting for the location of the fire source(s) and fire size(s) relative to relevant equipment so as to determine when the equipment could be damaged. As illustrated in Figure A-2, the starting point for the reactive actions will not necessarily be tied to the time associated with detecting and diagnosing the fire (T_1 in the figures). The symptoms for the reactive actions will occur whenever the fire affects the relevant equipment, which could be before T_1 is reached or anytime after that point. Thus, to repeat, the time available (T_3) for the reactive actions will be determined assuming the worst-case point for the spurious effects.

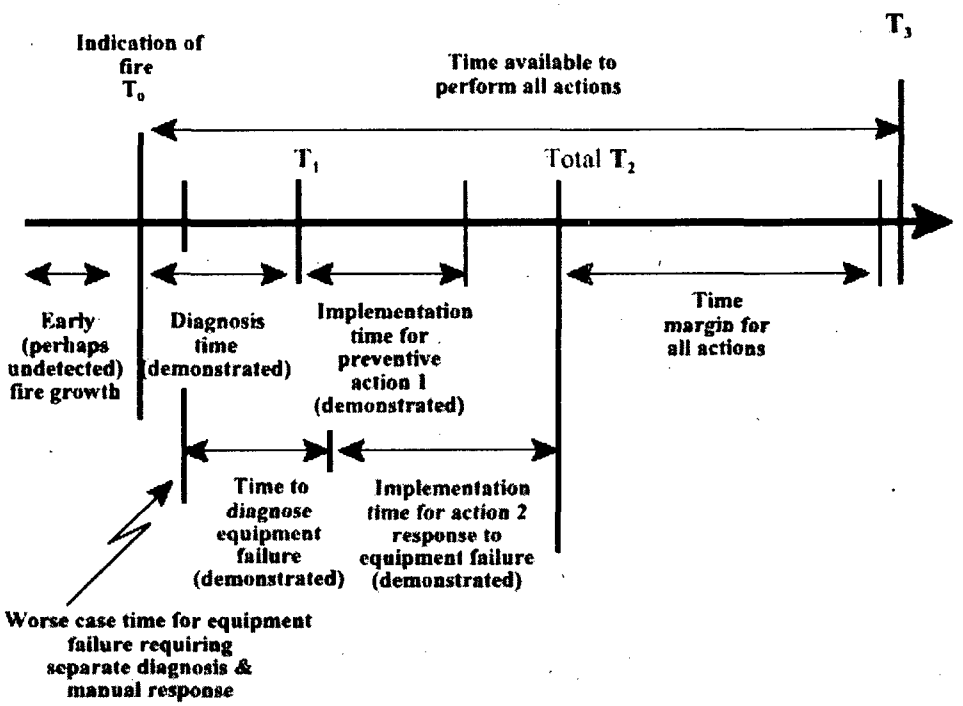

Figure A-2. Initial fire detection and multiple action (one action dependent on a separate diagnosis of an undesired equipment faulure) with a single overall time margin and T_3

Another consideration is relevant to the case of preventive actions. If it is reasonably possible that the fire could negatively affect the relevant equipment before the preventive actions are completed, then the implementation time (T_2) should also include the time it will take plant personnel to take the reactive actions necessary to manually place the affected equipment in the desired state. In other words, when reasonable, analysts should assume that the time to complete the desired action may have to include additional time to take further reactive actions to restore the equipment to the desired state if the fire could negatively affect the equipment before the preventive actions (that are meant to prevent the undesired state of the equipment) can be completed. This issue is addressed further in the information for performing the demonstration.

(4) Extra time or an added "time margin" to account for uncertainties in estimating the time to complete the action. (A method for determining the "time margin" is explained in Appendix B.)

(5) The time available for performing the actions to ensure hot shutdown can be achieved and maintained (T_3). T_2 plus the time margin should be less than or equal to T_3.

The relationship between having enough time and the associated demonstration is discussed in detail later. In calculating T_3, it should be shown that the available time is the most conservative (in this case, generally the shortest or minimum) time, considering the fire, its location and

anticipated growth rate, the fire effects, and expected plant and operator responses to the fire effects, including thermal-hydraulic calculations as necessary. To determine the most conservative T_3, which in this case is the minimum time available, since overestimating the time available could lead analysts to incorrectly conclude that the actions are feasible and reliable, the analyst needs to consider what failures (including spurious events) may occur and when they may occur. For example, if it is most conservative to assume the equipment failure occurs at the quickest possible time for the fire being analyzed (which may be even before any preventive actions could be taken for the fire, requiring subsequent response-type actions instead), then T_3 should be based on that assumption. For instance, loss of the feedwater function is generally more severe if it happens early in the scenario than if it happens later after a period of successful decay heat removal. If instead it is most conservative to assume the equipment failure occurs at some later time in the scenario, that time should be assumed in deriving T_3 (e.g., if failure of service water to a diesel after the diesel has been running and loaded is more severe than before the diesel is demanded because the diesel could fail in 3 minutes without cooling, so that the operator would likely prevent diesel operation, thereby "saving" it for future use if service water is restored).

As shown in Figure A-3, when developing any timeline showing multiple actions, any interdependence among actions needs to be accounted for, such as when actions by one operator cannot start before another action or actions are completed by another operator, or when multiple actions are to be performed by a single operator who must travel to multiple locations to perform his/her assigned actions in a sequential manner.

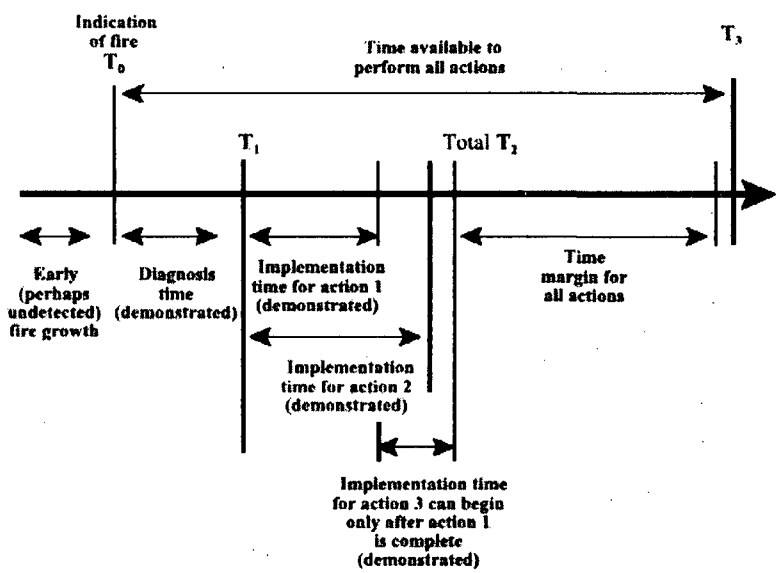

Figure A-3. Initial fire detection and multiple actions (one action dependent on completion of a prior action) with a single overall time margin and T_3

Depending on the desired actions, one overall time margin or multiple time margins and T_3 times (as illustrated in Figure A-4) may be necessary or appropriate to show that individual actions are performed before their specific analyzed T_3 times and that the collective set of actions to fully achieve and maintain hot shutdown are successfully performed considering the fire and its effects. Also, the analysts may wish to use a "most conservative" timeline for a range of fires, locations, and effects (in which case the timeline must envelop the needs of all the fires) or to develop separate timelines for different fire locations or even different fires in the same location.

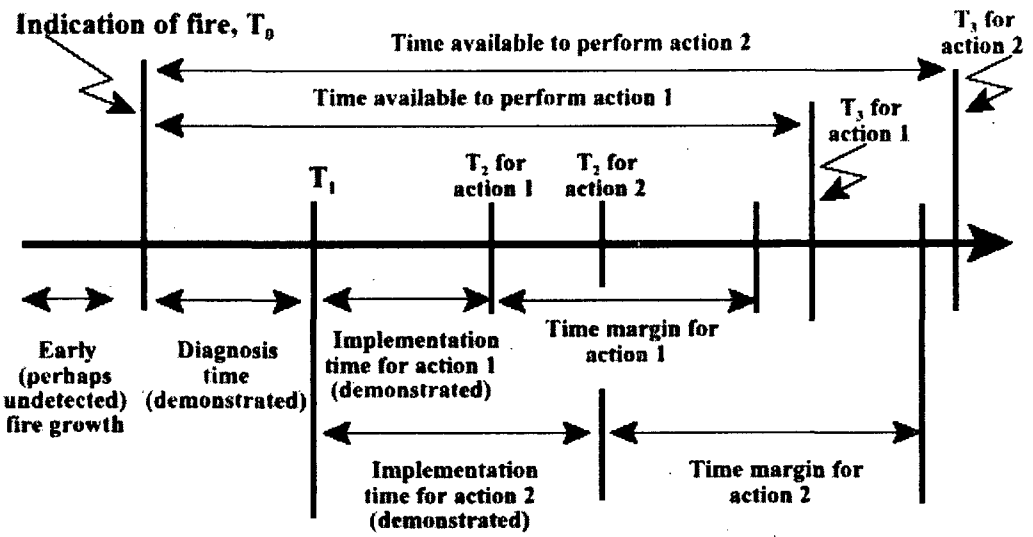

Figure A-4. Initial fire detection and multiple actions illustrating the application of multiple time margins and T_3s

Key inputs and assumptions associated with the timeline should be evident in the analysis documentation.

Depending on the desired actions, one overall time margin or multiple time margins and T_3 times (as illustrated in Figure A-4) may be necessary or appropriate to show that individual actions are performed before their specific analyzed T_3 times and that the collective set of actions to fully achieve and maintain hot shutdown are successfully performed considering the fire and its effects. Also, the analysts may wish to use a "most conservative" timeline for a range of fires, locations, and effects (in which case the timeline must envelop the needs of all the fires) or to develop separate timelines for different fire locations or even different fires in the same location.

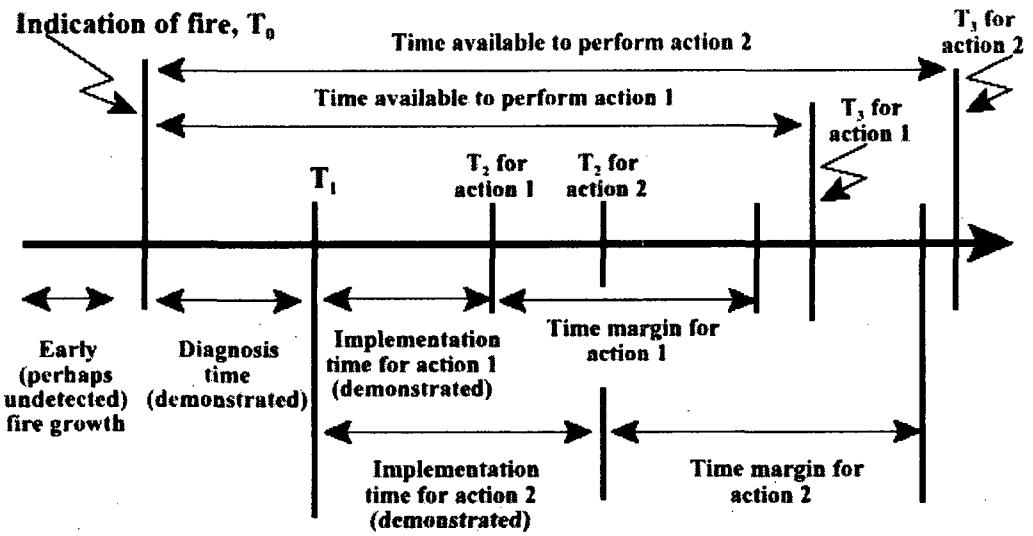

Figure A-4. Initial fire detection and multiple actions illustrating the application of multiple time margins and T_3s

Key inputs and assumptions associated with the timeline should be evident in the analysis documentation.

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APPENDIX B

SUMMARY OF EXPERT OPINION ELICITATION TO DETERMINE TIME MARGINS FOR OPERATOR MANUAL ACTIONS IN RESPONSE TO FIRE (April 1–2 and May 4–5, 2004)

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APPENDIX B
SUMMARY OF EXPERT OPINION ELICITATION TO DETERMINE TIME MARGINS FOR OPERATOR MANUAL ACTIONS IN RESPONSE TO FIRE (April 1–2 and May 4–5, 2004)

This appendix documents a process that was used during the initial efforts of the U.S. Nuclear Regulatory Commission's (NRC's) fire operator manual action proposed rulemaking and the development of an accompanying regulatory guide. Since the rulemaking effort was discontinued, this information is included as an appendix to this report to illustrate the thought processes that were used to address the uncertainties associated with the time to perform an operator manual action in response to fire. As such, this appendix describes an expert elicitation that was used to estimate how much additional time analysts might want to include to account for uncertainties that might not be covered by a demonstration of a given action. Analysts may find the discussion useful to their efforts associated with estimating the potential impact of the factors creating the uncertainties to ensure that there is adequate extra time, but it is not meant to imply that a factor of 2 extra time should always be shown or that analysts should always use such an approach in their analysis.

B.1 Introduction

This appendix summarizes the results from two expert opinion elicitation meetings held at NRC headquarters in Rockville, Maryland, to develop quantitative criteria to support the operator manual actions rulemaking [Ref. 1]. The NRC was developing these criteria to ensure that *feasible* operator manual actions could also be accomplished *reliably*, even when considering different levels of complexity, number of actions, etc.[1] Based on an initial meeting held on January 22–23, 2004, among NRC staff and contractors to discuss potential options for quantitative criteria, it was agreed that the use of "time margins" was appropriate as a surrogate for ensuring a high reliability in the credited local operator manual actions. As a result of that meeting, a plan was implemented to derive the best approach for providing defensible time margins.

The basic idea was to identify a time margin (or margins) for fire-related operator manual actions to ensure that they would be successful a very high percentage of the time (i.e., there is a high confidence of a low probability of failure). In other words, if analysts show in a demonstration that a randomly selected, established crew can successfully perform the actions, and show that the actions can be performed within a timeframe that allows for adequate time margin to cover potential variations in plant conditions and human performance, then the operator manual action would be shown to be reliable. For example, as long as analysts can show there is an "X-percent" time margin to perform a particular set of operator manual actions (e.g., the actions are shown during the demonstration to take less than 15 minutes, but even if they were assumed to take 30 minutes (or 100-percent time margin), plant damage or an undesirable plant condition will still be avoided) and all other important factors have been addressed, then they can be confident that the actions can be done reliably. Another approach may be to add a prescribed time (e.g., "Y" minutes) to the time obtained in a demonstration of any actions as a means to produce the desired increase in reliability.

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1 *Italicization* is used for emphasis.

The use of the time margin concept involves the derivation of appropriate time margins and a technical basis to support them. While the best technical basis would be empirical data from which the time margins could be derived, a database search was unable to find relevant data that could be used directly or generalized to the operator manual actions of interest. One potential exception was American National Standards Institute/American Nuclear Society (ANSI/ANS) Standard 58.8 [Ref. 2], which addresses time response design criteria for safety-related operator actions. However, it was determined that the data in ANSI/ANS 58.8 relevant to operator manual actions were limited and too broad to generalize well, they were probably overly conservative for most of the types of fire-related operator manual actions being considered, and they lacked clear and sufficient technical basis for our purposes.

Note that just one time margin was not necessarily being advocated; that is, the time margin could vary with the fire scenario, such that different margins may apply to different cases, regardless of whether the margins are measured in absolute (e.g., minutes) or relative (e.g., percent) time. Since varying time margins would most likely depend upon considerations such as fire frequency, magnitude, and consequences, this could be viewed as a form of "risk-informing" the criteria.

Thus, it was decided that an expert panel would be convened and that a facilitator-led, expert judgment process following the direct numerical estimation approach discussed in NUREG/CR-2743 [Ref. 3] and NUREG/CR-3688 [Ref. 4], in conjunction with the information and examples found in NUREG/CR-6372 [Ref. 5], would be used to identify reasonable time margins. The premise is that experts in the areas of nuclear power plant safety, risk assessment, inspection, fire safety and analysis, fire-related plant operations, human factors, and human reliability analysis could, in the context of a structured expert opinion elicitation process, make reasonable estimates of appropriate time margins.

B.2 First Expert Elicitation Meeting

A panel of six experts met at the NRC in Rockville, Maryland, on April 1 and 2, 2004. One week prior to the meeting, each expert was provided with a description of the goals of the meeting, which discussed many of the issues that would be addressed to generate the desired time margins.

B.2.1 Expert Panel and Qualifications

The six experts were as follows:

(1) a Team Leader, Plant Engineering Branch, Division of Reactor Safety, in Region IV of the NRC; also serving as a project manager and inspector (covering plant engineering and maintenance) for the NRC over the past 14 years

(2) a Reliability and Risk Engineer in the Probabilistic Risk Analysis Branch in the NRC Office of Nuclear Regulatory Research (RES); formerly a principal engineer (supervisor) and senior reactor operator at a commercial nuclear power plant licensee

(3) a Senior-Level Advisor for probabilistic risk assessment, Division of Systems Safety and Analysis, NRC Office of Nuclear Reactor Regulation (NRR); formerly a project manager in the Energy Risk and Reliability Department at a contractor for the nuclear power industry

(4) a principal of an independent contracting firm, especially contracting to Sandia National Laboratories, and recognized expert in the probabilistic analysis of fire and flood risk for nuclear and nonnuclear facilities; also a published author of numerous articles on this subject

(5) an Engineering Psychologist in NRR/NRC with expertise in the area of human factors for more than 20 years; also serving as an NRC human factors expert on a national standards development committee in the area of human reliability analysis

(6) a Senior Operations Engineer in NRR/NRC; formerly an NRC inspector for 20 years, starting as a region-based construction and fire protection inspector and including 8 years as a resident and senior resident at pressurized-water reactors (PWRs)

B.2.2 Summary of Topics Discussed During the First Meeting

Much of the first day, the discussion among the expert panel members and other meeting participants from NRR, RES, and RES contractors, including the elicitation facilitators, covered the following five topics:

(1) What is this expert opinion elicitation all about?

(2) What are the operator manual actions for which we are considering time margins?

(3) What are the human performance influences that should be accounted for by the time margins?

(4) What empirical data or other expert knowledge or experience may be relevant to developing the time margins and their bases?

(5) How will the elicitation process work?

B.2.2.1 What Is this Expert Opinion Elicitation All About?

With regard to topic 1, it was agreed that the overall goal was to derive time margins that would provide reasonable assurance that local operator manual actions in response to fire, in general, can be achieved with a high confidence of a low probability of failure (e.g., 95-percent confidence of a 0.01 failure probability). While it was thought that specific numerical goals on confidence and probability were not practical, the experts were easily able to understand the intent of what we wanted to achieve. Further, so that all the experts' conception of the time margin was the same, the "model" shown in Figure B-1 was agreed upon as generally representative of the time margin concept.

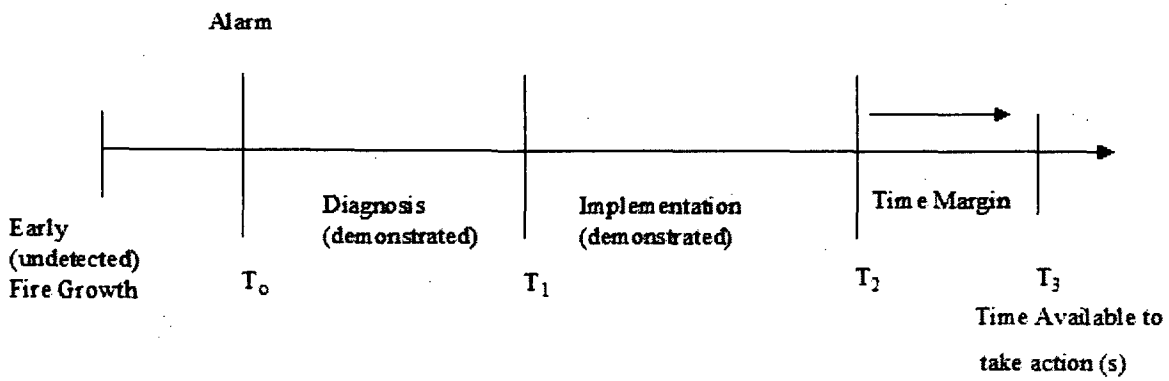

Figure B-1. Conceptual illustration of a time margin

B.2.2.2 What Are the Operator Manual Actions for Which We Are Considering Time Margins?

There was much discussion on topic 2. In particular, while it was agreed that we were addressing local (ex-control room) operator manual actions, there was confusion as to whether only preventive actions were included or whether reactive actions were also included. Further, there were clearly some differences in opinion as to when an action is a "repair." Preventive actions are those which, upon entering a fire plan/procedure, the licensee expects (without needing further diagnosis) to take to prevent spurious actuations or other fire-related failures so that adequate equipment is protected and hot shutdown can be achieved. Reactive actions constitute those taken during a fire in response to an undesired change in plant status and for which there is more of an element of detection of the undesired plant status and a diagnosis, with the aid of procedures, as to the correct actions to be taken. Further, there is precedence that repairs not be allowed for achieving hot shutdown.

While the expressed differences were not completely resolved, it was agreed that, in general, the following types of actions were *illustrative* of the types of actions we were concerned about:

- pulling fuses
- disconnecting power leads
- performing breaker manipulations (e.g., tripping, opening drawers, closing, changing switch positions) related to buses as well as individual loads such as valves, pumps, fans
- opening/closing/throttling of valves (e.g., with local switches, governor devices, handwheels)
- starting/stopping equipment, such as pumps and fans by either local switches/pushbuttons or breaker control
- installing jumpers or temporary power cables
- verifying or monitoring plant equipment or parameter status (and taking other actions as may be necessary based on these monitoring activities)

It was not the intent of this panel to define specifically what actions would or would not be allowed per the rulemaking that was in progress at the time. Therefore, the list above should not be construed as a list of what would have at that time been deemed "acceptable" operator manual actions. Nonetheless, it was agreed that the list was useful to generally define the typical kinds of actions for which time margins were to be considered, and that at least for purposes of the elicitation, both preventive and reactive actions would be addressed.

B.2.2.3 What Are the Human Performance Influences That Should Be Accounted for by the Time Margins?

With regard to topic 3, a number of observations were made. First, the rulemaking staff offered the following suggestions for the criteria:

- It should perhaps be made clear that the Available Indications criterion includes those indications necessary to detect and diagnose the location of the fire.
- It should perhaps be made clear that the Staffing and Training criterion allows both operators and maintenance staff to be involved as long as they are trained to take the desired actions.
- It should perhaps be made clear that the Communications criterion not only specifies that the communications systems must be adequate, but also that they must be readily available.
- It should perhaps be made clear that the Portable Equipment criterion specifically notes that such equipment includes what would be commonly referred to as "tools," such as keys, ladders, flashlights, gloves, and that these should be "staged" so that their locations are known and constant.
- It should perhaps be made clear that the Procedures criterion requires the use of *controlled* procedures.
- It should perhaps be made clear that, when multiple procedures will be required to be used simultaneously during a real fire (e.g., emergency operating procedures (EOPs) and the fire procedures), their simultaneous use will need to be part of the demonstration of operator manual actions in response to fires.

The staff offered these suggestions because it was clear that, in order to reasonably bound what the time margin was to account for, it was desirable that the other criteria be as specific and encompassing as possible. In this way, the time margin did not have to address potential inadequacies in meeting the other criteria and could focus on just those likely differences between what is expected in a typical demonstration of the actions vs. what might be experienced in a real fire situation (this became the basic premise for the time margin).

With this basic premise for the time margin, the discussion further elaborated upon what the time margin needed to take into account. Three possibilities were considered:

(1) The time margin should account for what an analyst is not likely to be able to recreate in the demonstration that could cause further delay (i.e., where the demonstration falls short), including the following examples:

- Random problems (i.e., not related to the fire) with instruments, indications, or other equipment such as a stiff handwheel or faulty communications device should be included.
- Environmental and other effects not easily included in the demonstration, such as smoke and toxic gas effects, increased noise levels due to the fire (e.g., alarms), water on the floor, fire hoses in the way, or too many people getting in each others' way, should be considered.
- Limitations of the demonstration to account for (or envelop) all possible fire locations where the operator manual actions are needed, resulting in different

travel paths and distances to these locations, should be evaluated. (A similar limitation concerns the location and activities of needed plant personnel at the time the fire starts that could delay their participation in executing the operator manual actions, e.g., they may be on the opposite side of the plant and may need to restore certain equipment before being able to participate).

- Inability to execute relevant actions during the demonstration because of normal plant status or safety considerations while at power should be included.

(2) The time margin should account for the fact that fire and related plant conditions can vary (e.g., fast energetic fire failing equipment quickly vs. slow-developing fire with little or no equipment failures for some time, variable fire detector response times and sensitivities, variable air flows affecting the fire and its growth, specific fire initiation location relative to important targets, presence (or not) of temporary transient combustibles, possible communication problems in some fires or in some noisy areas).

(3) The time margin should account for the typical variability in human performance among individuals and among different crews and for the effects of human-centered factors that could become relevant during fire scenarios, such as stress, issues related to human factors and ergonomics (e.g., height at which task is performed), time pressure, and fear of fire, including the following examples:

- physical size and strength differences
- cognitive differences (e.g., memory ability, cognitive style differences)
- emotional response to the fire/smoke
- response to wearing a self-contained breathing apparatus (SCBA) to accomplish a task (i.e., some people may be very uncomfortable with masks over their faces)
- individual sensitivity to real-time pressure
- team characteristics

Further, it was agreed that these items did need to be part of the time margin for the following reasons:

- They address likely shortcomings of the demonstration (e.g., operators may not actually do the demonstration while wearing SCBAs or they may not perform the demonstration with full replication of environmental conditions, such as propagation of water on the floor into the rooms where the actions are to take place as a result of suppression system actuation in the room with the fire). *It was felt such shortcomings could result in potentially significant differences between times for actions during a demonstration and the times during real fires.*
- The demonstration can attempt to replicate only a small subset of all possible fires and resulting variability in fire and plant conditions (see examples cited under item 2 above), some of which could be worse than assumed in the demonstrations. *It was felt such variability could result in potentially significant differences between times for actions during a demonstration and the times during real fires.*
- It was recognized that some degree of human performance variability is to be expected, some of which could further delay the times to perform the desired actions during real

fire situations. *It was felt such variability needed to be estimated and included in any derivation of time margins.*

Beyond this, it was agreed that the illustrative influences provided below, considering the categories mentioned above, were indeed representative of the influences that should be accounted for in the time margin:

- wearing SCBAs to complete the actions, which could affect performance in many ways, including the ability to communicate, etc. (use of SCBAs is not explicitly addressed by the rule criteria)
- substantial amounts of water on the floor from fighting the fire
- visibility problems due to smoke that is worse than assumed for the location of a given set of actions
- individual differences in the psychological effects of having to perform actions in proximity to a fire (even if the fire is not, in reality, physically threatening)
- inability to perform all of the subactions related to an "action" during a demonstration (e.g., the plant was "at-power" during the demonstration and certain actions could not be completely conducted while maintaining safety)
- time pressure (not sensed during demonstrations)
- the presence of less experienced staff, even though trained
- the need to identify alternate routes to and from the location of the operator manual actions because of the fire and its effects
- unexplained or unexpected equipment problems (e.g., a stuck handwheel, failures in communication equipment, misplaced tools, loss of lighting, loss of instrumentation)
- shortcomings in training not revealed during the demonstration
- inaccuracies in procedures for certain unique situations not previously identified (i.e., simply not thought of and not detected during the demonstration because the actual process could not be fully conducted)
- cases in which the fire is larger than expected and less time is available

Further, it was agreed that there could potentially be delays in either or both the diagnosis and decision to execute operator manual actions in response to fire as well as in the implementation of the desired manual actions; hence both effects should be considered when deciding on appropriate time margins.

While there was some discussion about how the analyzed time available (T_3) could be ascertained when it cannot be precisely known when a spurious or other fire-induced failure might occur, those discussions are not reproduced here since it was agreed that concerns about the appropriateness of T_3 (particularly as related to how to measure the time available for preventive actions) were not critical to the specific task before the experts. That is, determining the relevant time margins does not depend on the calculation of T_3.[2]

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[2] But the time margin is certainly relevant when evaluating whether the operator manual actions satisfy the timeline determined by T_3.

B.2.2.4 What Empirical Data or Other Expert Knowledge or Experience May Be Relevant to Developing the Time Margins and Their Bases?

Regarding topic 4, literature searches of easily available sources (only a short timeframe was available prior to the first elicitation) were performed in preparation for this meeting to seek any additional information that may be helpful to establish defensible time margins. Unfortunately, little was found. The following observations are provided to the extent they may be useful, but none of them are directly relevant to how to derive an appropriate time margin.

Actual events, recent inspections, and analytical processes suggest that, in spite of attempts to anticipate actual fire conditions and their effects, and then provide procedures, training, tools, communication devices, etc., so as to be able to perform the necessary or desired actions within expected time periods, the times to actually take the actions are often longer than prejudged estimates. The panel was prepared to discuss as many examples of this as may be desirable during the meeting. In some cases the difference between the actual time to perform the actions and the estimated time to take the actions has been small.

However, in extreme cases, as high as a threefold increase has been observed (i.e., it was estimated the actions could be taken within 30 minutes and the somewhat realistic time from a demonstration took nearly 90 minutes) for complex actions such as aligning, starting, and controlling a whole train of an injection system. In NUREG/CR-1278 [Ref. 6], it is noted that judgmental estimates are often low compared with actual times and that *a factor of 2 difference should not be unexpected.*

The above observations should be moot from our standpoint since the actions and their execution times are assumed to be obtained using the demonstration information. That is, the differences between judgmental estimates and times from the demonstration should not be an issue. Nonetheless, the above findings indicate that there may be time-delaying factors that are difficult to foresee, especially when other things can (and often do) go wrong. Thus, to the extent that the times from the demonstrations are still not entirely representative of all relevant actual fire situations (and demonstrating the actual times may be difficult, if not impossible, to achieve), it should not be surprising that the real times may still be even longer than what is obtained in a demonstration.

It was also observed that with regard to assessing risk significance, NEI-00-01 [Ref. 7] cites potential types of scenarios that should not be screened out as unimportant during the preliminary screening step of the information. Such a scenario includes one involving operator actions where both time is short (less than 1 hour) and the estimated time to perform the actions is greater than 50 percent of the available time. While not directly useful to deriving a defensible time margin, this step does seem to recognize that there may be factors that could make the time to perform the actions longer than estimated. The guidance implies that *a factor of up to 2 increase is desirable between the estimated time and the available time in order to provide adequate comfort that the actions can easily be performed in the available time.*

For the same reasons as cited earlier, this observation was not directly helpful as to how to derive a defensible time margin for action times obtained from a demonstration; however, it did support the idea that there are probably factors that can delay action times. Thus, a time margin is desirable to ensure that the actions can be reliably implemented.

B.2.2.5 How Will the Elicitation Process Work?

With regard to topic 5, the following process was used as initial expert opinion elicitations were performed on some sample cases:

- The facilitators summarized the relevant characteristics for which the time margin was being elicited (particularly, the types of actions and any relevant contexts for which the time margin applies, the relevant influences to be captured by the time margin, other applicable knowledge, experience, data, etc., and the form of the time margin). This was done in a facilitator-led discussion allowing experts to clarify these characteristics as necessary.
- Each expert privately estimated an appropriate recommended time margin.
- The experts' time margins were shared among the group and the experts were given the opportunity to provide their rationale for their estimates in a facilitator-led discussion. This identified legitimate considerations that were not accounted for by some experts, and it uncovered considerations that should not have been included by other experts. In either case, the results of the discussion caused some experts to provide a revised estimate.
- The experts were given a second (final) opportunity to privately arrive at a revised time margin.
- While we strove to reach a consensus on the identified time margins, the final elicited time margins from the experts were recorded and, as feasible, subsequently treated in a statistical manner to arrive at a single recommended time margin. (Following the completion of both expert opinion elicitation sessions, the facilitators decided that a strict statistical analysis was not warranted based on the limited results.)

Notes were taken during the entire meeting to subsequently and properly document the meeting's key discussions and decisions.

To support the experts in determining how best to derive their estimates of appropriate time margins, to help them decide what the forms of the time margins should be, and to determine how many different time margins were needed, the experts agreed that it would be helpful to consider a few sample operator manual actions and associated scenarios. The general goal was to see what could be learned by thinking about specific examples. From trying to determine appropriate time margins for a couple of specific cases, the experts thought they might be able to see trends, improve their understanding of the issues, and draw some general conclusions about time margins. In addition, it was proposed that, by examining specific cases of the types of fire operator manual actions being addressed and by considering the different types of influences thought to be important, the panel would better understand the nature of operator manual actions in response to fire and the ways in which the different influences might affect crew performance.

With these thoughts in mind, and with the remaining time available for the meeting, expert opinion elicitations were conducted on two example cases.

B.2.3 Example Elicitation Cases Addressed at the First Meeting

Two scenarios and related actions and timing were described to the experts for the example elicitation. One involved a preventive action that would be initiated as soon as the fire was

detected, while the other was a reactive action that would be diagnosed on the basis of plant symptoms and relevant procedures. However, the cases were similar in that they both concerned the inappropriate opening of power-operated relief valves (PORVs) as a result of the fire. This is an important issue because the unexpected opening of the PORVs in a PWR can result in a significant loss-of-coolant accident (LOCA).

B.2.3.1 First Scenario/Action Case

In the first example scenario, a fire starts in an area that has the potential to cause inappropriate opening of the PORVs. Per the procedure associated with a fire in this area, once the fire is detected and located, a plant equipment operator (PEO) is summoned to the main control room (MCR) if necessary (although PEOs generally report to the MCR when events such as fires occur), provided with the relevant procedure, and directed to travel to the correct cabinet, find the correct terminal block, and pull the appropriate fuses to prevent the PORVs from opening. The PEO was assumed to then need to inform the MCR crew to provide verification that the PORVs were deenergized.

For purposes of the exercise, it was assumed that, during the plant's demonstration of this fire-related operator manual action (actually a set of subactions), likely fires in this area would normally be detected and located within approximately 5 minutes. Since by procedure the presence of the fire indicates the need for the appropriate fuses to be pulled, it was assumed that under most conditions the diagnosis for the need for the actions and the retrieval of the relevant procedures would be made in the same timeframe. Thus, T_1 was assumed to take about 5 minutes.

With respect to the time to execute the operator manual actions (T_2), it was assumed that the demonstration conducted at the plant revealed that a randomly selected, established crew accomplished the actions within about 4 minutes. That is, the responsible MCR person assigns a PEO and gives him the relevant procedure and instructions (about 1 minute), the PEO travels to the appropriate cabinet (1 minute), identifies and pulls the relevant fuses (1 minute), and notifies the MCR that the action was completed (1 minute), for a total of 4 minutes. (The experts at the meeting (including a former operator) agreed that this was a reasonable estimate of the time necessary to complete such an action for many plants.) The analyzed time available to complete the action before a problem would occur (T_3) was assumed to be approximately 20 minutes.

Given this scenario, it was the experts' job to identify and consider the factors that might delay performance of this task under realistic plant fire conditions. Per the guidelines discussed above, it was assumed that all of the operator manual action criteria had been met by the plant.

For this initial exercise, the panel members considered the three influence factors from Section B.2.2.3 of this appendix, focusing mainly on the factors that might not be covered adequately during the demonstration (i.e., aspects of the rule criteria that would not be easily addressed during the demonstration and could cause delays if problems arose). However, and especially during their modified responses, the experts also considered variations in plant conditions and human-centered factors in determining their time margins.

Table B-1 displays the increases in the time that were suggested by the experts to account for factors that might not be covered completely by the demonstration, as well as potential variability in plant conditions and fire scenarios and additional human influences. The

suggested time increases cover factors that could reasonably delay the performance of the preventive actions associated with pulling fuses to prevent the PORVs from inadvertently opening due to the fire.

Table B-1 Initial and Revised Additional Times Added to Combined T_1 and T_2

Panel Member	Increase (Added to Original 9 min)		Factor (Total Time to Original 9 min)	
	Initial Estimate	Revised Estimate	Initial Estimate	Revised Estimate
#1	23 min	10 min	3.5	2.1
#2	6 min	10 min	1.7	2.1
#3	11 min	12 min	2.2	2.3
#4	6.5 min	9 min	1.7	2
#5	30 min	18 min	4.3	3
#6	1 min	10 min	1.1	2.1

A review of Table B-1 reveals a significant amount of variability in initial estimates of the amount of time that should be added to T_1 and T_2 to account for uncovered influences. After the panel members had the opportunity to discuss their results and share their reasoning with one another, much closer agreement was reached and, for the most part, the expert panel was converging on a factor of approximately 2 as an appropriate time margin for this case. That is, if it were assumed that the time to pull the fuses to prevent the opening of the PORVs might be twice as long as was obtained in the demonstration and still fall within T_3, then it would be appropriate to credit the action. In this case, since T_3 was assumed to be 20 minutes, and increasing the original time from the demonstration of 9 minutes by a factor of 2 results in a total of 18 minutes, then the reliability of the action would be shown.

However, it should be remembered that, as discussed at the end of Section B.2.2.5 of this appendix, the goal of the exercise was to see what could be learned by thinking about specific example cases. It was hoped that the exercise would support the experts' determination of how best to derive their estimates of appropriate time margins, to help them decide what the forms of the time margins should be, to familiarize them with the different types of influences thought to be important and how to consider their effects, and to determine how many different time margins might be needed.

B.2.3.2 Second Scenario/Action Case

The second scenario and action case examined at the meeting essentially served the same purpose as the first. That is, the goal was to continue to familiarize the panel members with the process and the factors to be considered to identify reasonable time margins for operator manual actions in response to fire.

For the second example (as with the first), the scenario involved a fire that starts in an area with the potential to lead to inappropriate opening of the PORVs. However, in this case, it was assumed that there is a reliance on a reactive process to deal with the potential opening of the PORVs. That is, the crew waits until there are some indications that the PORVs have opened,

and then they send personnel out to pull the fuses to allow the PORVs to close (as a backup to the likely attempted closure of the PORV block valves).

For purposes of the exercise, it was once again assumed that it would take approximately 5 minutes to detect and locate the fire. In addition, it was assumed that another 2 minutes would pass before the fire caused the PORVs to open. Once the PORVs opened, it was assumed that the plant was able to show in the demonstration that diagnosis of the presence of the opened PORVs and contacting personnel to perform the needed actions could be done in about 1.5 minutes. Moreover, as in the preventive case, 3 minutes were assumed to travel to the cabinet, pull the fuses, and verify completion of the task with the MCR. Thus, in this case it was assumed that 4.5 minutes would be necessary to diagnose the need for the actions and to complete them, such that $T_1 + T_2 = 4.5$ minutes for the reactive case.

A difference between the reactive case and the preventive case is that the detection and location of the fire is not part of the assessment of the time margin.[3] Since the time between the start of the fire and the opening of the PORVs can be quite variable, the plant will be concerned with ensuring that, regardless of when the PORVs open, the PORVs will be closed in time to prevent any serious damage. Thus, the analyzed time available (T_3) is the worst-case time between the opening of the PORVs and the point at which serious damage would occur.

The only time that the activities associated with detecting and locating the fire would be relevant in the reactive case would be when the PORVs opened within the first 5 minutes after the fire starts. However, for this example it was assumed that the PORVs did not open until 2 minutes after the fire was located and detected. Thus, the panel focused on how much time they would need to add to the 4.5 minutes of T_1 and T_2 in order to account for the three influence factors discussed in Section B.2.2.3 above.

However, two caveats are relevant to this second example exercise. First, only a short period of time was available at the end of the second day of the elicitation session to perform the exercise, compelling the expert panel members to rush their judgments somewhat. Furthermore, based on discussions with the panel members, at least some did not agree that, for the case we were addressing, the activities occurring before the PORVs opened would not be relevant to the crew's performance in diagnosing the open PORVs and ensuring their closure by pulling the fuses. Thus, some panel members included adjustments to the fire location and detection phase and added that to their time adjustments, while others did not. Due to the limited time available for this example exercise, it was not possible in all cases to separate these extra time additions from the panel's estimates. In addition, there was not time for the panel to revise their initial estimates.

Table B-2 displays the increases in the time that were suggested by the experts to account for factors that might not be covered completely by the demonstration, as well as potential variability in plant conditions and fire scenarios, and additional human influences. The suggested time increases cover factors that could reasonably delay the performance of the reactive actions associated with pulling fuses to allow the PORVs to go closed before serious damage occurs.

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[3] Note that not all the panelists dismissed this time as irrelevant and included time margins in their overall assessment to account for influences that could arise during this specific interval.

Table B-2 Initial Time Added for Diagnosing the Need and Successfully Closing Open PORVs

Panel Member	Increase (Added to Original 4.5 min)	Factor (Total Time to Original 4.5 min)
#1[4]	13 min	2.1
#2	7.5 min	2.7
#3	7.5 min	2.7
#4	7.5 min	2.7
#5	25 min	6.6
#6	8.5 min	2.9

Despite some potential confounds with this example as discussed earlier in this section, it is worth noting that several experts were fairly close in their estimates. Based on the discussions with the expert panel members and the results above, it was considered possible that the time margin for reactive operator manual actions could be higher than for preventive actions.

B.2.4 Conclusion from First Meeting

As a result of the meeting, considerable insight was gained into reasons why it may be necessary to add a time margin to demonstration times and how large that time margin may need to be. At the end of the meeting, it was agreed that an additional elicitation meeting was necessary to pursue other representative examples of scenarios and actions to further learn what time margins would be appropriate for local operator manual actions in response to fire.

B.3 Second Expert Elicitation Meeting

The same panel of six experts (described in Section B.2.1 above) participated in the second expert opinion elicitation session held at the NRC in Rockville, Maryland, on May 4 and 5, 2004. Approximately 2 weeks prior to the second meeting, each expert was provided with a summary of the first meeting and given the opportunity to review the report, verify its contents (in particular the results of the example expert opinion elicitations), and make recommendations for changes. All panel members concurred with the summarized results of the first meeting as presented. In addition, a few days prior to the second meeting, an agenda for the second meeting was sent to the expert panel. The agenda noted the general steps planned for the meeting, reviewed important results from the first meeting, discussed the goals of the second meeting, outlined outstanding issues related to the time margins still to be addressed, and provided initial discussions of two possible examples for the second meeting.

[4] Panelist 1 added time for fire detection and location as well as to diagnosis of the open PORVs. Thus, the 13 additional minutes were compared relative to a total original time of 11.5 minutes rather than 4.5 minutes.

B.3.1 Summary of Topics Discussed During the Second Meeting

In the first meeting, two general types of local operator manual actions in response to fire were addressed and issues associated with the two types were discussed. The two types were preventive and reactive actions. Because some panel members and the facilitators had given additional thought to these types of actions since the last meeting, it was decided that the second meeting would begin by returning to a discussion of these types of actions.

B.3.1.1 Preventive Actions

It was repeated that for the preventive actions, it is generally assumed that once the fire has been detected and located, per procedure, the MCR crew directs someone to execute a number of actions that will prevent fire-related damage to equipment to ensure its availability to achieve its function during the fire scenario. Also by procedure, the only criterion for initiating these actions is the presence of the fire itself. However, in reality it is possible that crews may delay initiation of the actions for some period just to make sure that the fire is significant enough to initiate the actions. Moreover, it may take time for the appropriate crew member to retrieve the relevant procedures and assign plant personnel to complete the actions, etc.

During the second meeting some additional points were discussed about the preventive actions relevant to crediting them under the proposed operator manual action rule. First, it was noted that there are no guarantees that all preventive actions can be completed before the relevant equipment might be affected by the fire. There are many different kinds of fires in terms of initial size, growth rate, etc., and they can start in different locations within a room. Thus, while in many cases it may be relatively unlikely that a fire would spuriously affect equipment before the equipment could be protected by the operator manual actions, it is probably impossible to say that given actions can always be completed prior to the relevant equipment being affected by the fire. This being the case, it was argued that to take credit for such actions, it would need to be assumed that operators may have to perform reactive actions to restore the equipment to its functional state.

While panel members noted that plant procedures for preventive actions generally include steps to verify that the actions were successful, and if not, to take actions to ensure the equipment is placed in the appropriate state, they also noted that when demonstrating the feasibility of the actions and measuring the time it takes to complete the actions, these potential additional steps should be included. In other words, all preventive actions have the potential to involve reactive actions to ensure the availability of the equipment and, therefore, those additional steps should be included in demonstrating the actions and measuring the time to complete the action. The panel pointed out that while the resulting time estimates to complete the actions may be conservative for the cases in which the preventive actions are successful, if such aspects are included in the plant demonstration, then they should not have to be accounted for in the time margin.

The latter point became a critical aspect of the second expert elicitation meeting. The panel members argued that to be able to develop a reasonable time margin for operator manual actions in response to fire, the demonstrations of the actions should cover as many potential influences on performance as possible. Furthermore, the most reasonably conservative cases for the various conditions that could influence the ability of crews to complete the actions should be incorporated into the demonstration. In this way, the more extreme and less frequent variations in performance may be accounted for in the identified time margins, thereby making their development simpler and easier to justify.

It was argued that the appropriate range of conditions to be included in the plant demonstrations should be described. The result would be that the applicability of the time margins identified from this exercise would be contingent on plant staff demonstrating the actions as specified, for instance, in this document. Aspects to be included in the demonstration are discussed in Section B.3.1.4 of this appendix.

A final aspect about preventive actions discussed by the panel concerned how to measure the time to complete the actions (T_3). If there are at least some fire events that could affect important equipment before the preventive actions could be completed, then the time available to complete the actions (before serious equipment damage could occur and affect hot shutdown) should be measured from the earliest point at which the relevant equipment could be affected. Thus, if it is at all reasonable, analysts should assume that the fire could start exactly in the area where the equipment of concern would be affected at the earliest possible time. This may result in less time being available for preventive actions than might normally be assumed, which should be considered when analysts develop their timelines for operator manual actions in response to fires.

B.3.1.2 Reactive Actions

For the reactive actions, operators do not initiate the actions until they have detected and diagnosed that the relevant equipment has been affected by the fire and that it may be needed for hot shutdown. That is, they do not initiate the actions until the procedure, given the relevant indications, calls for the reactive actions. However, the panel noted that the symptoms indicating that the equipment has been affected could occur very early in the scenario when the crew is still in the process of detecting and locating the fire, entering initial EOPs, and possibly entering abnormal procedures. Alternatively, the symptoms could occur later in the scenario after the crew has been responding to the situation for a while and fire-specific procedures have been initiated. It was argued that, since the effect on the equipment could occur very early (e.g., as a result of an explosive switchgear fire), potential delays due to initial competing activities should be considered in determining the time margins. However, the panel was unable to conclude that the activities occurring during early stages of a fire scenario would necessarily be any more demanding that those occurring somewhat later in a scenario. It would seem that the demands of a given scenario across time would be plant- and scenario-specific; thus, this would be a factor that should be addressed by each plant for reactive actions, and the most reasonably conservative case with respect to potentially competing tasks should be modeled in the plant demonstration. If this is done, then any developed time margins would not have to take such effects into account.

The panel acknowledged that crews may find themselves dealing with "dueling procedures" at any point in a fire scenario and that the effects of possibly being in multiple procedures should be modeled to the extent possible during the demonstration of operator manual actions in response to fire.

Regarding the time available to complete reactive actions, T_3 would be determined by how much time would be available to restore the critical equipment after the fire effects had occurred in the context of the accident scenario.[5] Analysts should assess the worst case for when the effects could occur and calculate the time available on that basis. In many instances, it would seem that fire damage occurring as early as possible in the scenario would be the most serious (due to more time to build up to the expected high heat levels), but there may be some scenarios where this would not be the case. Again, analysts should consider such aspects in developing their timelines for the actions.

B.3.1.3 Other Types of Actions

Two other general categories of actions were considered by the panel. They included simple vs. complex actions and short-term vs. long-term actions. With respect to the latter, it was argued that essentially all local operator manual actions in response to fire would be relevant only in the short-term case (i.e., within the first hour of the scenario). Thus, it was decided that this distinction would not be relevant for developing the time margin.

However, over the 1.5 days of the meeting, the simple vs. complex distinction was discussed on several occasions. The issue was whether separate time margins would be needed for simple actions, such pulling a fuse, vs. more complex actions, such as multiple-task actions that involve coordination and communication among plant personnel. After examining the potential ways in which complexity might vary, it was decided that the nature of the specific actions being carried out by plant personnel would not vary significantly. That is, the actions being conducted by individuals would be of the general types of actions on which plant personnel are trained and perform routinely as part of their jobs. Thus, the complexity would more likely come from the coordination and communication associated with some activities and the associated time aspects.

The panel eventually concluded that, since both simple and complex actions would have to meet the same criteria in the (planned but discontinued) rule, and because time differences between tasks could be accounted for by using a common multiplier (e.g., a factor of 2 as a "time margin" multiplier on the demonstration) across all tasks, separate time margins as a function of complexity would not be needed. In fact, the panel eventually concluded that, *as long as all the (planned) rule criteria were met, the operator manual action demonstrations were performed appropriately (as described in the planned regulatory guide), and the time available for the various tasks was calculated appropriately, then a single time margin could be adopted.* The single time margin would cover all the remaining influences unaccounted for by the demonstration and could be applied generally to all types of operator manual actions in response to fire, including preventive and reactive actions. The influences on performance to be covered by the time margin and those to be covered by the demonstration are discussed below.

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5 However, time zero would still be measured at initial fire detection, such that a plant using reactive type procedures would not necessarily have as much time to take actions as one with preventive procedures, due to the time delay between fire detection and initiation of operator manual actions.

B.3.1.4 Influences on Performance

Based on the results of the first meeting, the three influence factors listed in Section B.2.2.3 of this appendix were again assumed to be relevant to identifying an appropriate time margin. That is, it was thought that there were three factors that could lead to variations in the performance of the operator manual actions that would not generally be accounted for by meeting the rule criteria. Thus, it would be necessary to account for such influences in the time margin.

After further consideration of these sets of influences during the second meeting, the panel agreed that many of the aspects of the influence factors could be covered by assuming "worst-case" scenarios in both the conditions associated with a plant's demonstration of actions and in their calculation of how much time would be available to complete actions before serious equipment damage would occur and affect hot shutdown. As discussed above, such conservatism would limit the number of influence aspects that would have to be covered by the time margin.

The panel ultimately agreed that influence factor 2 (variability in fire and related plant conditions) should be addressed in the analyst's calculation of the time available for actions (T_3). Analysts should assume the worst-case reasonable variations in fire characteristics and plant conditions that could affect the time available to complete actions in that calculation. In addition, the panel agreed that some aspects of influence factor 1 (where the demonstration falls short) could be adequately addressed by making certain assumptions or simulating certain conditions during the demonstration. The demonstration should address the following aspects (among others):

- If it is reasonably likely that operators will wear SCBAs to complete actions, then they should wear them during the demonstration. Furthermore, if communication is necessary between operators under conditions in which they would wear SCBAs, then the communication should be achieved while wearing the SCBAs.
- If normal plant noise levels could affect communication in some areas, the demonstrations should be conducted under those conditions.
- If smoke could significantly affect visibility, then actions should not be credited.
- If it is possible that needed operator manual actions will involve plant personnel (e.g., PEOs) being summoned from other locations in the plant to obtain instructions and relevant procedures and proceed to the area of the actions, then the worst-case reasonable time for them to travel to the various locations, which may include traveling to the MCR, should be included in the time to execute the actions. In other words, in conducting the demonstration, necessary personnel should be located as far away as reasonable at the start of the simulation. In addition, the potential for such personnel to have to complete what they were doing before responding should also be considered in the demonstration and, therefore, in the time to complete the actions.
- If the fire or other factors could affect where personnel have to travel (e.g., what routes they have to take) and where they have to enter various rooms, then the worst-case reasonable effects should be modeled in the demonstration.
- If multiple actions (or multiple sets of actions) will have to be performed and coordinated and potential interference could occur, then all should be simulated in the demonstration.

The main point is that analysts should carefully analyze the potential context for given operator manual actions in response to fire and strive to model the worst-case, yet credible scenarios in their demonstrations. That is, they should do a good job of setting up their demonstrations to avoid being overly optimistic. For example, they should not select their most recently trained crew and then allow them to prepare for the demonstration (i.e., no "preconditioning").

B.3.1.5 Impact of Human Errors

Another topic of discussion concerned the impact of potential human errors in performing operator manual actions and the associated recovery actions. It was pointed out that, while the main goal of developing a time margin for local operator manual actions in response to fire was to cover the range of influences that could delay performance of the various actions, it is also possible that personnel could make errors in performing the actions. Although the probabilities of such errors may be relatively low, when they do occur, operators should be able to identify that an error has occurred and recover from the failure. Since verification is required for the operator manual actions (the proposed rule required that there be reliable indications available that actions have been completed), then it is reasonable to expect that the existence of any incorrectly performed actions or omissions could be detected. However, since it is probably not realistic to assume that analysts will model such recoveries in their demonstrations, the panel agreed that there should be at least some time built into the time margin to cover recovery actions (even if the likelihood of such errors occurring and not being caught immediately would be relatively low).

B.3.2 Determination of Time Margin

In order to determine an appropriate time margin, as in the first meeting, the panel thought that the process of stepping through reasonable examples of local operator manual actions in response to fire for estimating time margins was a useful exercise. By examining the various actions in some detail and thinking about how much delay could occur due to specific influences, it was thought that a good sense for a reasonable time margin would be obtained.

For this exercise in the second meeting, a somewhat more complex example of a preventive action (set of subactions) was addressed. This scenario was the third addressed across the two expert opinion elicitation meetings.

B.3.2.1 Third Scenario/Action Case

In this scenario, a fire starts in an area that has the potential to lead to inappropriate alignment or otherwise failure of the component cooling water (CCW) system. Per the procedure associated with a fire in this area, once the fire is detected and located, and in order to prevent CCW failure (the fire can supposedly affect all the equipment in Division A [Div-A] CCW, which is supposed to keep running, and the fire can potentially affect the Division B [Div-B] CCW valves, but not the Div-B pump, which does not start unless the Div-A train malfunctions), two PEOs are summoned to the MCR if necessary (PEOs generally report to the MCR when events such as fires occur). They are provided with the relevant fire procedure and are directed to travel to two locations; PEO 1 goes to the East Switchgear Room (ESWGR) and PEO 2 travels to the Div-B CCW room (the division to be protected). These rooms should not be affected by smoke from the fire, but the Div-B CCW room could, in a real fire, have a little water on the floor

from nearby sprinkler operation if drains become partially plugged and some overflow occurs (this cannot be part of the demonstration).

Upon reaching their respective locations, PEO 1 is to communicate via radio with the MCR supervisor. The MCR staff then manually starts the Div-B CCW train and, after ensuring it is operating properly, the MCR staff shuts down the Div-A CCW train and pulls-to-lock the Div-A CCW pump. To protect the continued operability of the Div-B CCW train, PEO 1 is to pull three of many specifically labeled breakers (two breakers in one electrical cabinet at one end of the ESWGR and one breaker in a different cabinet at the other end of the ESWGR) that remove power from three Div-B CCW valves so they will stay in the proper position. PEO 1 is then to confirm with the MCR supervisor (via radio) that this is done and that Div-B CCW is continuing to adequately handle heat removal from the various loads. The MCR then informs PEO 2 (who has been listening in on his radio from the Div-B CCW room) that the Div-B CCW train is operating and that the manual crosstie valve between the CCW trains needs to be closed. PEO 2 then closes the manual crosstie valve in the Div-B CCW room and contacts the MCR and PEO 1 to confirm closure of the valve.

In the meanwhile, PEO 1 moves to the West Switchgear Room (WSWGR) and pulls the Div-A CCW pump breaker to ensure the pump cannot spuriously operate. PEO 1 then informs the MCR supervisor that the alignment is complete. The MCR supervisor verifies the alignment of the system via indicator lights, flows, and temperature indications and then releases the PEOs so they can attend to other matters.

Steps of the actions and times from the demonstration (or assumed times) are as follows:

Step 1. For purposes of the exercise, it was assumed that, during the plant's demonstration of this fire and the operator manual actions, it was simulated that likely fires in this area would normally be detected and located within approximately 5 minutes.

Step 2. Three additional minutes are expended for the PEOs to have reached the MCR and obtained the procedure and directions for the CCW manipulations (so now 8 total minutes have passed).

Step 3. PEO 1 and PEO 2 reach their locations (travel time) and call in on the radios to ensure communication with each other and the MCR—4 minutes (so total time is now 12 minutes).

Step 4. MCR staff starts Div-B CCW train, shuts down Div-A CCW train, pulls-to-lock the CCW A pump, and tells PEO 1 it is OK to pull breakers—1 minute (so total time is now 13 minutes).

Step 5. PEO 1 pulls the breakers in the ESWGR and communicates with the MCR who ensure continued operation, and the MCR then informs it is OK to close the manual CCW valve—3 minutes (so the total time is now 16 minutes).

Step 6. PEO 2 closes the manual valve and informs the MCR and PEO 2 of its closure—4 minutes (so the total time is now 20 minutes)

Step 7. PEO 1 travels to the WSWGR, opens pump breaker, and communicates to MCR that this act is complete—3 minutes (so the total time is now 23 minutes).

Step 8. MCR verifies all is OK and communicates to PEOs that they are released—1 minute (so the total time is now 24 minutes).

Table B-3 summarizes the expert panel's judgments for this scenario. In particular, the table shows the various steps of the actions being addressed, the time (assumed) for the actions obtained during the demonstration, and each panel member's judgment regarding what the total time for each step would be after adding time to account for various influence factors. Note that, at this point during the meeting, firm conclusions had not yet been reached regarding which factors should be addressed during the demonstration in calculating available time, as opposed to what should be included in the time margin. In fact, much of that information came out of discussions held during and after the scenario exercise. Which of the three general influences from Section B.2.2.3 above that the panel considered potentially relevant for each step of the action is noted in the table.

Table B-3 Total Time for Each Step of the Action for the Third Scenario, by Panel Member (Base Time Plus Time Added for Influence Factors)

Step and (Base Time)	Relevant Influence Factors	Panel Members' Total Times for Each Step (min)					
		#1	#2	#3	#4	#5	#6
1—(5 min)	#3	5	5	5	5	5	5
2—(3 min)	All	4	5	4	4	3	3
3—(4 min)	All	6	4	6	6	7	5
4—(1 min)	#1, #3	1.5	1	2	2	2	1.5
5—(3 min)	All	5	5	5	6	5	4.5
6—(4 min)	All	7	5	8	14	7	5
7—(3 min)	All	5	3	3	7	3	3
8—(1 min)	All	1.5	2	1	2	3	1
Total (24 min)		35	30	34	46	33	28

Each panel member considered how he or she thought the different influence factors might lead to increases in the time to complete each step of the action. A review of the table indicates that the total increases range from a factor of 1.25 to about 2, with an average of about 1.5, or an increase of 50 percent in the time. After the panel members had discussed the reasons for their additions, many thought that a factor of 1.5 to 2 might be a reasonable time margin for operator manual actions. However, they also recalled that, in working through the earlier examples, some panel members had identified greater relative time increases and had been considering significantly larger time margins.

B.3.2.2 Fourth Scenario/Action Case

By the time the fourth scenario was addressed, several discussions had taken place and the panel had agreed that influence factor 2 associated with fire characteristics and plant conditions should be addressed by analysts in determining the time available to complete the actions (as discussed in Section B.2.2.3 above). Similarly, the panel had identified several important factors that might lead to significant variation in performance that should also be addressed by analysts in conducting the demonstrations and noted that this should be made clear. Thus, in

the final exercise, there were two major goals. One was to assess actions assuming the plant had performed a proper demonstration. The second was to address a preventive action that included the situation in which the equipment was affected by the fire before the preventive measures were completed, requiring the operators to perform the relevant reactive actions. The idea was that by addressing a hybrid, they would have the opportunity to assess a range of potential influences under conditions different from those considered before.

The example used was similar to that used for the third scenario, except that in this case, in addition to PEO 1 having to pull the breakers for the Div-B CCW valves in the ESWGR and communicating with the MCR and PEO 2, PEO 1 will have to travel to the relevant room and verify and check on the valve positions of the Div-B CCW valves and readjust as necessary. In this case, it is assumed that the Div-B CCW system has been affected by the fire and the operators enter a more reactive mode. For the exercise, it was assumed that three alignment valves in Div-B CCW have spuriously closed. PEO 1 will need to reopen the valves and take the steps necessary to restore flow.

The steps considered in the elicitation were the same as before (see Section B.3.2.1 of this appendix) with the following exceptions:

Step 5. Normally, PEO 1 pulls the breakers in the ESWGR and communicates with the MCR crew, who ensure continued operation, and the MCR then informs PEO 2 that it is OK to close the manual CCW valve—3 minutes (so the total time is normally 16 minutes). However, now PEO 1 discovers that three of the valves have spuriously closed and need to be repositioned. PEO 1 needs to reopen the valves, restore flow to the Div-B CCW system, and inform the MCR—12 minutes added (so now the total is 28 minutes).

Step 7. Deleted (small effect; limited time remaining to panelists).

Step 8. Deleted (small effect; limited time remaining to panelists). For this exercise the scenario was ended after Step 6, so the total time was 32 minutes (previous 24 total minutes plus additional 12 minutes from Step 5 minus 4 minutes from Steps 7 and 8).

For this final exercise, the expert elicitation was done in a manner slightly different from the other examples. This was partially attributable to the limited time remaining on the second day; it was viewed as an approximate but expedited way to combine both the initial and revised estimation steps. In this case, each member decided how much time he or she thought needed to be added to each step of the operator manual action based on the influences, and the panel discussed the basis for the selected times among themselves. Finally, each member settled on a value he or she thought was reasonable and the facilitators documented the range of values proposed by the panel. In cases in which several panel members were in agreement about the values, the mode (most repeated value) was also identified.

Table B-4 presents the results of the final elicitation, displaying the times added by panel members from considering influence factors that could not be covered in the demonstration (influence factor 1 in Section B.2.2.3 above) and the times added by considering human-centered influences (influence factor 3 in Section B.2.2.3). As noted above, aspects associated with fire characteristics and plant conditions (influence factor 2 in Section B.2.2.3) were assumed to be addressed by the plant and were not covered in the example.

Table B-4 Time Added to Each Step of the Manual Action for the Fourth Scenario (Hybrid Case of a Preventive and a Reactive Action)

Step and (Base Time)	Influence Factor 1 (Demonstration Shortfalls)	Influence Factor 3 (Human-Centered Factors)
1—Fire detected and verified (5 min)	No time added	No time added
2—PEOs to MCR (3 min)	1 min (panel agrees)—minor smoke, obstacles, etc.	0.5–1.5 min
3—PEOs to remote locations (4 min)	1–2 min—minor smoke, communications delays	0.5–2 min
4—MCR starts CCW B train and stops the A train (1 min)	0.2–1 min—MCR activities (fire distractions)	0–0.5 min
5—PEO 1 initially pulls breakers (3 min)	0–0.5 min	1–3 min (mode = 1.5 min)
5a—PEOs 1 and 2 determine that three valves on Div-B CCW have already spuriously closed. Re-open valves and restore system (12 min)	2–6 min	2–3 min (mode = 3 min)
6—PEO 2 closes crosstie (4 min)	2–4 min (assumed water on the floor, or other conditions.)	1–3 min (mode = 2 min)
Total (32 min)	Total of 6.2–14.5 min added	Total of 5–13 min added

When the total time added for the two influences categories are combined, the range of times to be added to cover their impact is 11.2–27.5 minutes. When these times are added to the base times (in the first column), the range is 43–60 minutes, which once again would represent an increase in the base time of roughly 50–100 percent.

B.4 Identification of Time Margin and Conclusion

Based on their reviews of the influence factors, the results of the example elicitations, and the need to allow some time for potential recovery actions, the panel members agreed that *a time margin factor of at least 2 would allow for a "high confidence of a low probability of failure" for local operator manual actions in response to fire.* The implication at the time with respect to the rulemaking activity was that, as long as operating plants meet the rule criteria for the actions (address the appropriate factors), they perform sound demonstrations of the actions at the plant (as described herein), perform reasonable calculations of the time available for the various actions (information for which is discussed herein), and can show that the time available is at least 100 percent greater than the time obtained in the demonstration, then local operator manual actions in response to fire could be considered reliable.

B.5 Characteristics of an Expert Elicitation Panel

As noted in the introduction to this appendix, analysts may find the discussion of the expert elicitation process useful to their efforts associated with estimating the potential impact of the factors creating the uncertainties to ensure that there is adequate extra time. While analysts may prefer a different approach for evaluating the uncertainties associated with manual actions (particularly if they are relatively simple and plenty of extra time is clearly available), if an expert panel elicitation is used, this section provides a brief summary of the characteristics and types of expertise that would be appropriate for such a panel.

An expert elicitation panel is typically composed of independent specialists, recognized in at least one of the areas/specialties addressed by the topic under evaluation. Generally, a multidisciplinary team approach should be used. The technical disciplines involved may vary depending on the particular topic (e.g., fire scenario) being analyzed (i.e., if there is a radiation hazard associated with the fire scenario, a radiation protection specialist or health pPhysicist may be needed as part of the team). In general, the expertise required could include human reliability analysis, human factors, fire protection, operations, instrumentation and control engineering, training, procedure development, probabilistic risk assessment, and other expertise as indicated by the fire scenarios and actions being examined. The team's objective is to arrive at an estimate of the time margin necessary to envelop the uncertainties associated with manual actions through consensus of the members.

An expert elicitation panel has both advantages and disadvantages. The principal advantage of the panel is the participants' knowledge and expertise in the subject area. Additionally, the pane! approach can provide significant reductions in time and cost allocations compared to other evaluation techniques, and leverage the credibility of conclusions because of the panel members' expertise. The tool also has limitations, significant among them is the elimination of minority view points because of consensus-based conclusions and the potential for the view of a "dominant" member to be overly influential in the decisionmaking process. Additionally, there is evidence that operators can sometimes be optimistic about action implementation times and such bias needs to be controlled [Ref 6]. References 5 and 8 provide information and other references on controlling for various sources of bias.

B.6 References

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Exhibits FP no. 17, 18, 19 omitted

Exhibit FP No. 20

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FROM: DUE: 10/13/04

EDO CONTROL: G20040668
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Representative Sue W. Kelly

TO:

Chairman Diaz

FOR SIGNATURE OF : ** PRI ** CRC NO: 04-0607

Chairman Diaz

DESC:

Cable and Raceway System at Indian Point 2
(William Lemanski)

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Virgilio
Kane
Merschoff
Norry
Dean
Burns/Cyr
Dyer, NRR
Rathbun, OCA

DATE: 09/30/04

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ADDRESSEE:	Nils Diaz		
SUBJECT:	The Commission's handling of the concerns by former Indian Point 2 employee William Lemanski...plant's cable and raceway system		
ACTION:	Signature of Chairman		
DISTRIBUTION:	RF, OCA to Ack		
LETTER DATE:	09/17/2004		
ACKNOWLEDGED	No		
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September 17, 2004

Dr. Nils J. Diaz
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20006

Dear Chairman Diaz:

The commission's handling of the concerns raised by former Indian Point 2 employee William Lemanski continues to trouble me. I am very disappointed that despite repeated requests for a complete walk-down of the plant's cable and raceway system, that this proposal has not yet been supported by the NRC.

Mr. Lemanski remains unsatisfied with the level of scrutiny given to this matter. The attached letter from David Lochbaum from the Union of Concerned Scientists seems to further underscore these concerns and compels me to once again urge the NRC to appropriately address this issue. At a time when plant security and safety is of paramount concern to communities surrounding the Indian Point Energy Center, it is critically important that the NRC do everything it can to ensure the safe operation of this facility. Again, I urge your support for an immediate and thorough inspection of the plant's cable and raceway system.

Your prompt attention to this request is greatly appreciated.

Sincerely,

Sue W. Kelly
Member of Congress

Union of Concerned Scientists

Citizens and Scientists for Environmental Solutions

September 17, 2004

Mr. Brian E. Holian, Director
Division of Reactor Projects
United States Nuclear Regulatory Commission Region I
475 Allendale Road
King of Prussia, PA 19406-1415

SUBJECT: ELECTRICAL CABLE SEPARATION SAFETY ISSUES AT INDIAN POINT ENERGY CENTER

Dear Mr. Holian:

NRC Inspection Report No. 50-247/2004009 dated August 20, 2004, documents the findings from the NRC's inquiry into the allegations made by former employee William Lemanski about cable separation issues affecting safety at Indian Point Unit 2. The NRC inspectors identified three violations of federal regulations that NRC characterized as Green in the reactor oversight process.

From January 1980 until August 1983, I worked for the Tennessee Valley Authority (TVA) at their Browns Ferry nuclear plant – the site of the infamous 1975 fire that disabled all of the safety systems used to cool the Unit 1 reactor and the majority of those systems on Unit 2. The near miss forced the NRC to promulgate Appendix R to 10 CFR Part 50 with expanded requirements for cable separation and fire protection. In researching TVA's extensive files on that pivotal event, I learned that the NRC's cable separation and fire protection regulations had been violated at Browns Ferry and that both TVA and the NRC had known about the many violations for a long time before the fire. TVA and NRC tolerated these many longstanding violations because they were deemed insignificant from a safety perspective – at least until the fire proved otherwise.

I truly hope that there's a difference between Indian Point Unit 2 today and Browns Ferry then other than the fact that Indian Point has not yet had a fire test its deficiencies. But I do not see much in the NRC inspection report to give me that hope. The violations at Indian Point that the NRC characterized as having "very low safety significance" are no less egregious than the violations the NRC knew about prior to the Browns Ferry fire. Because comparable "very low safety significance" violations at Browns Ferry would have prevented the 1975 fire from causing serious damage had they been corrected instead of tolerated, perhaps you can understand why no one living around Indian Point should take comfort in the NRC downplaying chronic cable separation violations at Indian Point. After all, TVA could claim ignorance of the fact that "very low safety significance" violations could contribute to a major accident. Entergy cannot claim ignorance given Browns Ferry's notoriety, leaving maybe only an insanity plea if a fire were to ravage Indian Point.

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Some specific comments on the NRC's inspection report:

1. The NRC licensed Indian Point Unit 2 in the 1970s. At that time, the electrical cables were supposed to be properly separated. Numerous reviews and evaluations have been conducted since then to re-verify cable routing such as following the issuance of Appendix R following the Browns Ferry fire, during the 1989-1995 Cable Separation Program, and during the development and issuance of IP2-DBD-222, "Design Basis Document for Cable Separation," Rev. 1, December 17, 2003 (see page 5 of the inspection report). Despite these initial and subsequent efforts, cable separation violations continue to be found, demonstrating that Indian Point has never been in compliance with the federal safety regulations.

2. On page 7, the NRC stated, "*Simply put, ECRIS, which is used at other plants, is not readily compatible with IP2's specialized cable separation criteria.*" On page 1, the NRC stated "*An NRC inspection was conducted ... to review issues associated with Entergy's conversion from WARS to ECRIS.*" [NOTE: WARS and ECRIS are acronyms for computer-based systems for tracking the routing of electrical cables.] On page 14, the NRC wrote, "*They also acknowledged the existence of a large number of data errors in WARS.*" So, Entergy took the WARS database that was known to contain a large number of errors and converted it to ECRIS that was known to be incompatible with the cable separation schemes employed at Indian Point Unit 2. Collectively, the findings in the NRC inspection report strongly suggest that Entergy made a bad situation at Indian Point worse.

3. On page 14, the NRC stated "*Because WARS and ECRIS are not relied upon in the manual cable routing process at IP2, the cable separation experts had confidence that the DVTR anomalies were not indicative of actual cable separation issues.*" Later in the very same paragraph NRC stated "*The IP2 designers and engineers were in general agreement that WARS had been a valuable tool in aid them in developing the design modification drawings (DMDs) that acted as cable separation routing schedules needed to install cables at the plant.*" So, WARS was not used during the manual cable routing process, but the drawings developed from WARS were used. If WARS is flawed, then the drawings developed from corrupted WARS are also suspect. Thus, any cables routed using WARS, ECRIS, and/or the drawings developed from WARS/ECRIS may violate the cable separation criteria unless independently verified by field walk-downs.

4. On page 14, NRC stated "*Because WARS and ECRIS are not relied upon in the manual cable routing process at IP2, the cable separation experts had confidence that the DVTR anomalies were not indicative of actual cable separation issues.*" On page 16, NRC states "*WARS and ECRIS provide the only tool capable of generating cable schedules for IP2, and as such are useful as long as engineers and designers are sensitive to the inaccuracies in the data.*" Several points:

    a. First, the statement on page 14 appears false. If WARS and ECRIS are the only tools for generating cable schedules, then WARS and/or ECRIS would have to be relied upon in the manual cabling routing process. [NOTE: A cable schedule is essentially the Rand McNally roadmap explaining how a cable is routed from Point A to Point B. The "roads" specify conduits, cable trays, and cable raceways.]

    b. On page 13, NRC stated "*The inspectors determined that training on the use of WARS was not provided to engineers and designers in a timely or systematic manner prior to the termination of the use of WARS in May 2002.*" It is extremely difficult for engineers and designers to be "*sensitive to the inaccuracies in the data*" unless they receive proper training, which clearly did not occur at Indian Point Unit 2. The statement about the engineers and designers being untrained but sensitive appears little more than a gratuitous attempt to gloss over a safety problem.

The NRC inspection report documented several unresolved cable separation problems that violated federal safety regulations. But since none of the few cable separation problems resolved so far revealed a major safety problem, NRC assumed that no major safety problem exists in the remaining unresolved problems. Whether NRC's guess is right or wrong is not the point. The burden is on the plant's owner to comply with regulations because compliance provides assurance of acceptable safety. Entergy has not met that burden. And the NRC is Entergy's accomplice by improperly shifting the burden from Entergy to workers like Mr. Lemanski who must now not only find cable separation violations, but find ones so significant as to shake NRC from its Rhett Butler approach to safety. Absent full compliance (and the large inventory of cable separation problems at Indian Point Unit 2 makes full compliance impossible), no one knows if the plant has acceptable safety levels.

In other words, the NRC is gambling today with known violations at Indian Point as it did in the 1970s with known violations at Browns Ferry. When the NRC lost the gamble with the 1975 fire at Browns Ferry, it reacted by promulgating more regulations. Law-making is futile when the NRC seems unable, or unwilling, to prevent law-breaking.

Sincerely,

<ORIGINAL SIGNED BY>

David Lochbaum
Nuclear Safety Engineer
Washington Office

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WASHINGTON, DC 20515-3219

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Chairman
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